أدنوك
ADNOC

ADNOC GROUP PROJECTS AND ENGINEERING

AUTOMATION AND INSTRUMENTATION DESIGN PHILOSOPHY

Philosophy

APPROVED BY:

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EFFECTIVE DATE:

AGES-PH-04-001

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شركة بترول أبوظبي الوطنية
Abu Dhabi National Oil Company

GROUP PROJECTS & ENGINEERING FUNCTION/ PT&CS DIRECTORATE

CUSTODIAN	Group Projects & Engineering / PT&CS
ADNOC	Philosophy applicable to ADNOC & ADNOC Group Companies

REVISION HISTORY

DATE	REV. NO	PREPARED BY (Designation / Initial)	REVIEWED BY (Designation / Initial)	ENDORSED BY (Designation / Initial)	ENDORSED BY (Designation / Initial)
09-Feb-2021	1	Asadullah Malik Sr. Engineer, I&C, TE. Digitally signed by Asadullah Malik DN: cn=Asadullah Malik, o=ADNOC, ou=AGP, email=asadullahm@adnoc.ae, c=AE Date: 2021.02.16 22:12:43 +04'00'	Ashwani Kumar Kataria/ A/MIHE,TC-Eng Digitally signed by Ashwani Kumar Kataria DN: cn=Ashwani Kumar Kataria, o=ADNOC Onshore, ou=ADNOC Onshore, email=akataria@adnoc.ae, c=AE Date: 2021.03.31 13:38:43 +04'00' Reuben Yagambaram/ SPM GPE Reuben Yagambaram Digitally signed by Reuben Yagambaram Date: 2021.04.13 15:58:23 +04'00'	Abdulla Al Shaiba/ VP-GPE 21/04/2021	Zaher Salem/ SVP-GPE 22/04/2021

The Group Projects & Engineering Function is the owner of this Philosophy and responsible for its custody, maintenance and periodic update.

In addition, Group Projects & Engineering Function is responsible for communication and distribution of any changes to this philosophy and its version control.

This philosophy will be reviewed and updated in case of any changes affecting the activities described in this philosophy.

INTER-RELATIONSHIPS AND STAKEHOLDERS

a. The following are inter-relationships for implementation of this Specification:

   i. ADNOC Upstream and ADNOC Downstream Directorates; and

   ii. ADNOC Onshore, ADNOC Offshore, ADNOC Sour Gas, ADNOC Gas Processing. ADNOC LNG, ADNOC Refining, Fertil, Borouge, Al Dhafra Petroleum, Al Yasat

b. The following are stakeholders for the purpose of this Specification:

   i. ADNOC PT&CS Directorate

c. This Specification has been approved by the ADNOC PT&CS is to be implemented by each ADNOC Group company included above subject to and in accordance with their Delegation of Authority and other governance-related processes in order to ensure compliance.

d. Each ADNOC Group company must establish/nominate a Technical Authority responsible for compliance with this Specification.

DEFINITIONS

“ADNOC” means Abu Dhabi National Oil Company.

“ADNOC Group” means ADNOC together with each company in which ADNOC, directly or indirectly, controls fifty percent (50%) or more of the share capital.

“Approving Authority” means the decision-making body or employee with the required authority to approve Policies and Procedures or any changes to it.

“Business Line Directorates” or **“BLD”** means a directorate of ADNOC which is responsible for one or more Group Companies reporting to, or operating within the same line of business as, such directorate.

“Business Support Directorates and Functions” or **“Non- BLD”** means all the ADNOC functions and the remaining directorates, which are not ADNOC Business Line Directorates.

“CEO” means chief executive officer.

“Group Company” means any company within the ADNOC Group other than ADNOC.

“Philosophy” means this Automation and Instrumentation Design Philosophy.

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1 GENERAL

1.1 Introduction

This philosophy provides requirements for automation and instrumentation design.

This philosophy covers:

a. Field instruments.

b. Analysers.

c. Fire and Gas Detection / Devices and related Notification devices.

d. Final Element / Output Devices.

e. Machinery Protection and Condition Monitoring System.

f. Instrument Design.

g. Instrument Installation.

h. Automation Philosophy.

This philosophy does not cover:

a. Development of functional safety documentation.

b. Fiscal or custody transfer metering packages. Refer to the relevant COMPANY Business Unit Standard(s) for further technical requirements.

c. Telecommunications equipment.

d. Instrument design requirements for subsea installations.

1.2 Purpose

The purpose of this philosophy is to define the minimum mandatory technical requirements for design, manufacturing, testing, packing, installation and commissioning of Automation and Instrumentation Equipment across the ADNOC Business Units. Unless otherwise stated in this philosophy, the supplied equipment shall comply fully with the requirements of relevant AGES, ADNOC Group standards / guidelines, industry, national and international standards.

The requirements detailed within this philosophy apply to both offshore and onshore installations, unless specifically stated to apply for either one or the other, i.e. a requirement starting with “for installations offshore” applies only to equipment to be located on an offshore installation.

This philosophy provides the structure to support standardisation and its associated savings in lifecycle costs, including total cost of ownership, maintenance requirements.

1.3 Defined Terms and Abbreviations

The following defined terms are used throughout this philosophy:

‘COMPANY’ means ADNOC, ADNOC Group or an ADNOC Group Company, and includes any agent or consultant authorized to act for, and on behalf of the COMPANY.

'CONTRACTOR' means the parties that carry out all or part of the design, engineering, procurement, construction, commissioning, or management for ADNOC projects. CONTRACTOR includes its approved MANUFACTURER(s), SUPPLIER(s), SUB-SUPPLIER(s) and SUB-CONTRACTOR(s).

"**MANUFACTURER**" means the Original Equipment Manufacturer (OEM) or MANUFACTURER of one or more of the component(s) which make up a sub-assembly or item of equipment assembled by the main SUPPLIER or his nominated SUB-SUPPLIER.

'may' means a permitted option.

'should' means a recommendation.

'shall' indicates mandatory requirements.

"**SUB-CONTRACTOR**" means any party engaged by the CONTRACTOR to undertake any assigned work on their behalf. COMPANY maintains the right to review all proposed SUB-CONTRACTORs; this right does not relieve the CONTRACTOR of their obligations under the Contract, nor does it create any contractual relationship between COMPANY and the SUB-CONTRACTOR.

"SUPPLIER" means the party entering into a Contract with COMPANY to provide the materials, equipment, supporting technical documents and/or drawings, guarantees, warranties and/or agreed services in accordance with the requirements of the purchase order and relevant specification(s). The term SUPPLIER includes any legally appointed successors and/or nominated representatives of the SUPPLIER.

"**SUB-SUPPLIER**" means the sub-contracted SUPPLIER of equipment sub-components software and/or support services relating to the equipment / package, or part thereof, to be provided by the SUPPLIER. COMPANY maintains the right to review all proposed SUB-SUPPLIERS, but this right does not relieve the SUPPLIER of their obligations under the Contract, nor does it create any contractual relationship between COMPANY and any individual SUB-SUPPLIER.

'[PSR]' indicates a mandatory Process Safety Requirement.

For the purpose of this AGES, the following Technical Definitions apply:

Term	Definition
SIS System	It is an Electrical / Electronic / Programmable Electronic safety-related System that provides the safeguarding of the process and equipment to protect personnel, assets and environment. It comprises of sensors/transmitters, the final control elements, and the logic solver.
Full Functional Test	Full testing of the element along with associated logic. (In case of ESD valves it is full close/open/close or open/close/open cycle test).
PFD	A value that indicates the probability that a device or system will fail to respond to a demand in a specified interval of time.
Reliability	The probability that when operating under stated environmental conditions, the system will perform continuously, as specified, over a specific time interval.
Fail Safe	The capability to go to a predetermined safe state in the event of a specific malfunction.
Fault-Tolerant System	A system incorporating design features which enable the system to detect and log transient or steady-state fault conditions and take appropriate corrective action while remaining on-line and performing its specified function.
MTTF	"Mean Time to Failure" is the expected time to failure of a system in a population of identical systems.

Term	Definition
MTTR	Mean Time to Restore" is the statistical average of time taken to identify, repair a fault (including diagnosis) and restore.
Overhaul Testing	Complete overhauling of the element and performing a full functional test (For ESD valves it includes TSO testing where specified).
Process Safety Time	The process safety time is defined as the time period between a failure occurring in the process or the basic process control system (with the potential to give rise to a hazardous event) and the occurrence of the hazardous event if the safety instrumented function is not performed.
Response Time	Total maximum time required to read all field inputs, program execution and change field output state at I/O card channel level.
Safety Instrumented Function (SIF)	Safety function with a specified safety integrity level which is necessary to achieve functional safety, and which can be either a safety instrumented protection function or a safety instrumented control function.
Safety integrity	Average probability of a safety instrumented system satisfactorily performing the required safety instrumented functions under all the stated conditions within a stated period of time.
Safety Integrity Level (SIL)	Discrete level (one out of four) for specifying the safety integrity requirements of the safety instrumented functions to be allocated to the safety instrumented Systems. Safety integrity level 4 has the highest level of safety integrity; safety integrity level 1 has the lowest.
SIL Validation	Activity of demonstrating that the safety instrumented function(s) and safety instrumented system(s) under consideration after installation meets in all respects the safety requirements specification.
SIL Verification	Activity of demonstrating for each phase of the relevant safety life cycle by analysis and/or tests that, for specific inputs, the outputs meet in all respects the objectives and requirements set for the specific phase.
Tight Shut Off (TSO)	The tight shut off requirement for valves shall be specified as per ISO 5208 and shall be followed during ESD valve Overhaul testing. Refer to AGES-SP-04-005 for requirements for ESD/EBDV valves.
Watchdog	Combination of diagnostics and an output device (typically a switch) for monitoring the correct operation of PES device and taking action upon detection of an incorrect operation.

The abbreviations used throughout this philosophy are shown in Table 1.1,

Table 1.1 – List of Abbreviations

Abbreviations	
AMS	Alarm Management System
APC	Advanced Process Control
BMS	Burner Management System
CCR	Central Control Room
CCTV	Closed Circuit Television
CIT	Communications Interface Testing

Abbreviations	
CPP	Central Processing Plant
CPU	Central Processor Unit
EDG	Emergency Diesel Generator
EDP	Emergency Depressurisation System
EMC	Electromagnetic Compatibility
EMI	Electromagnetic Interference
EPC	Engineering, Procurement and Construction
ESD	Emergency Shutdown System
FAT	Factory Acceptance Test
FDS	Functional Design Specification
FEED	Front End Engineering and Design
FGS	Fire and Gas System
FPSO	Floating Production and Storage Facility
GPS	Global Positioning System
GWR	Guided Wave Radar
HART	Highway Addressable Remote Transducer
HAZOP	Hazard and Operability Review
HVAC	Heating, Ventilation and Air Conditioning
HIPPS	High Integrity Pressure Protection System
HMI	Human Machine Interface
HSE	Health, Safety and Environmental
HSSD	High Sensitivity Smoke Detection
IAMS	Instrument Asset Management System
ICSS	Integrated Control and Safety System
ID	Internal Diameter
IES	Instrument Equipment Shelters
IFAT	Integrated Factory Acceptance Test
IP	Ingress Protection
IR	Infra-Red
IS	Intrinsically Safe
I/O	Inputs/Outputs
JB	Junction Box
LAN	Local Area Network
LCD	Liquid Crystal Display

Abbreviations	
LCP	Local Control Panel
LED	Light Emitting Diode
LEL	Lower Explosive Limit
LFL	Lower Flammable Limit
LOPA	Layers of Protection Analysis
LPG	Liquid Petroleum Gas
LQ	Living Quarters
MAC	Main Automation Contractor
MAWP	Maximum Allowable Working Pressure
MCR	Main Control Room
MLG	Magnetic Level Gauge
MMS	Machinery Monitoring System
MOS	Maintenance Override Switch
MOV	Motor Operated Valve
MRB	Manufacturing Record Book
MSDS	Material Safety Data Sheet
MTTF	Mean Time to Failure
MTTR	Mean Time to Restore
NB	Nominal Bore
NDT	Non-Destructive Testing
NIS	Non-Intrinsically Safe
NPS	Nominal Pipe Size
OD	Outside Diameter
OEM	Original Equipment Manufacturer
OPCO	Operating Company
OT	Operational Technology
PAD	Production Asset
PAGA	Public Address / General Alarm
PC	Personal Computer
PCP	Pre-commissioning procedure
PCS	Process Control System
PES	Programmable Electronic System
PFD	Probability of Failure on Demand
PLC	Programme Logic Controller

Abbreviations	
PRV	Process Relief Valve
PST	Partial Stroke Test
PTFE	Polytetrafluoroethylene
PVC	Polyvinyl Chloride
QA	Quality Assurance
QC	Quality Control
RFI	Radio Frequency Interference
RTD	Resistance Temperature Detector
RTJ	Ring Tight Joint
SAT	Site Acceptance Test
SCADA	Supervisory Control and Data Acquisition.
SDSS	Super Duplex Stainless Steel
SG	Specific Gravity
SIF	Safety Instrumented Function
SIL	Safety Integrity Level
SIS	Safety Instrumented System
SIT	Site Installation Test
SMART	Single Modular Auto-ranging Remote Transducer
SMC	Safety Management Control
SSSV	Subsurface Safety Valve
TETRA	Terrestrial Trunked Radio
TCP/IP	Transmission Control Protocol / Internet Protocol
UCP	Unit Control Panel
UPS	Uninterruptible Power Supply
UV	Ultra Violet
WHCP	Well Head Control Panel

SECTION A - GENERAL

2 REFERENCE DOCUMENTS

2.1 International Codes and Standards

The following Codes and Standards shall form a part of this philosophy. When an edition date is not indicated for a Code or Standard, the latest edition in force at the time of the contract award shall apply.

AMERICAN GAS ASSOCIATION (AGA)

AGA Report No. 3	Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids
AGA Report No. 9	Measurement of Gas by Multipath Ultrasonic Meters
AGA Report No. 11	Measurement of Natural Gas by Coriolis Meters

AMERICAN PETROLEUM INSTITUTE (API)

API 2350	Overfill Prevention for Storage Tanks in Petroleum Facilities
API 520	Sizing, Selection, and Installation of Pressure-relieving Devices
API 526	Flanged Steel Pressure-Relief Valves
API 670	Machinery Protection Systems
API MPMS 14.3 All parts	Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids
API MPMS 5.2	Measurement of Liquid Hydrocarbons by Displacement Meters
API MPMS 5.3	Measurement of Liquid Hydrocarbons by Turbine Flow Meters
API MPMS 5.6	Measurement of Liquid Hydrocarbons by Coriolis Meters
API MPMS 5.8	Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters
API RP 551	Process Measurement Instrumentation
API RP 552	Transmission Systems
API RP 553	Refinery Valves and Accessories for Control and Safety Instrumented Systems
API RP 554	Process Control Systems
API RP 555	Process Analyzers

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME)

ASME PTC 19.3 TW - 2016	Thermowells Performance Test Codes
ASME B1.20.1	Pipe Threads, General Purpose (Inch)
ASME B31.3	Process Piping
ASME MFC-21.2	Measurement of Fluid Flow by Means of Thermal Dispersion Mass Flowmeters

ASME MFC-11	Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters
ASME MFC-3M	Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi

AMERICAL SOCIETY FOR TESTING AND MATERIALS (ASTM)

ASTM A269	Standard Specification for Seamless and Welded Austenitic Stainless-Steel Tubing for General Service.
ASTM A276	Standard Specification for Stainless Steel Bars and Shapes.
ASTM A450/A450M	Standard Specification for General Requirements for Carbon and Low Alloy Steel Tubes.
ASTM A479/A479M	Standard Specification for Stainless Steel Bars and Shapes for Use in Boilers and Other Pressure Vessels.
ASTM A789/A789M	Standard Specification for Seamless and Welded Ferritic/Austenitic Stainless-Steel Tubing for General Service.
ASTM B265	Standard Specification for Titanium and Titanium Alloy Strip, Sheet and Plate.
ASTM B338	Standard Specification for Seamless and Welded Titanium and Titanium Alloy Tubes for Condensers and Heat Exchangers.
ASTM B348	Standard Specification for Titanium and Titanium Alloy Bars and Billets.
ASTM B444	Standard Specification for Nickel-Chromium-Molybdenum-Columbium Alloys (UNS N06625 and UNS N06852), Nickel-Chromium- Molybdenum Silicon Alloy (UNS N06219) Pipe and Tube.
ASTM B446	Standard Specification for Nickel-Chromium-Molybdenum-Columbium Alloys (UNS N06625), Nickel-Chromium-Molybdenum Silicon Alloy (UNS N06219) and Nickel-Chromium-Molybdenum-Tungsten Alloy (UNS N06650) Rod and Bar.
ASTM B706	Standard Specification for Seamless Copper Alloy (UNS C69100) Pipe and Tube.
ASTM B829	Standard Specification for General Requirements for Nickel and Nickel Alloys Seamless Pipe and Tube.

BRITISH STANDARDS (BS)

BS 4800	BS 4800 Colour Chart
BS 3463	Specification for observation and gauge glasses for pressure vessels
BS 6739	Code of practice for instrumentation in process control systems: installation design and practice
BS 8452	Use of clamp-on (externally mounted) ultrasonic flow-metering techniques for fluid applications. Guide

DEUTSCHES INSTITUT FÜR NORMUNG (DIN)

DIN 7081	Pressure resistant oblong sight glasses of borosilicate glass without limitation in the range of low temperature

ENERGY INSTITUTE (EI)

EI 15	Model Code of Safe Practice Part 15: Area Classification Code for Installations, Handling Flammable Fluids.

ENGINEERING EQUIPMENT and MATERIALS USERS ASSOCIATION (EEMUA)

EEMUA Publication 191	Alarm systems - a guide to design, management and procurement
EEMUA Publication 201	Control rooms: a guide to their specification, design, commissioning and operation

EUROPEAN STANDARDS (EN)

EN 55022	Information technology equipment. Radio disturbance characteristics. Limits and methods of measurement
EN 61326	Electrical equipment for measurement, control and laboratory use. EMC requirements. Immunity requirements for safety-related systems and for equipment intended to perform safety-related functions (functional safety). Industrial applications with specified electromagnetic environment

ENERGY INDUSTRIES COUNCIL (EIC)

CCI P/3	Control Panels

INTERNATIONAL ELECTROTECHNICAL COMMISSION (IEC)

IEC 60079	Electrical apparatus for explosive atmospheres - All parts
IEC 60255	Measuring relays and protection equipment
IEC 60331	Tests for electric cables under fire conditions
IEC-60332	Tests on electric and optical fibre cables under fire conditions
IEC 60364-4-44	Low-voltage electrical installations - Part 4-44: Protection for safety - Protection against voltage disturbances and electromagnetic disturbances
IEC 60381	Analogue signals for process control systems - All parts.
IEC 60382	Analogue pneumatic signal for process control systems

IEC 60529	Degrees of protection provided by enclosures (IP Code)
IEC 60534-8	Industrial-process control valves - Part 8-1: Noise considerations - Laboratory measurement of noise generated by aerodynamic flow through control valves
IEC 60584	Thermocouples
IEC 60751	Industrial platinum resistance thermometers and platinum temperature sensors
IEC 60770-1	Transmitters for use in industrial-process control systems - Part 1: Methods for performance evaluation
IEC 60812	Failure modes and effects analysis (FMEA and FMECA)
IEC 61831	On-line analyser systems - Guide to design and installation
IEC 61000	Electromagnetic Compatibility (EMC) - All parts.
IEC 61131	Programmable Controllers – All Parts
IEC 61508	Functional safety of electrical/electronic/ programmable electronic safety related systems
IEC 61511	Functional safety. Safety instrumented systems for the process industry sector.
IEC 62305	Protection against lightning (for electrical, lightning protection is implemented for buildings, MCR and tall structures irrespective of risk based considering the importance of the facility to national economy).
IEC 62382	Control systems in the process industry - Electrical and instrumentation loop check
IEC 62591	Industrial communication networks – Wireless communication network and communication profiles – WirelessHART™
IEC 62734	Industrial networks - Wireless communication network and communication profiles - ISA 100.11a
IEC TR 61831	On-line Analyser Systems - Guide to Design and Installation
IECEx	IEC System for Certification to Standards relating to Equipment for use in Explosive Atmospheres (IECEx System)

INTERNATIONAL SOCIETY OF AUTOMATION (ISA)

ISA 5.1	Instrument Symbols and Identification
ISA 7.0.01	Quality Standard for Instrument Air
ISA 84.00.01	Functional Safety: Safety Instrumented Systems for the Process Industry Sector
ISA 84.91.01	Identification and Mechanical Integrity of Safety Controls, Alarms, and Interlocks in the Process Industry

ISA RP60.1	Control Center Facilities
ISA RP60.3	Human Engineering for Control Centers
ISA S71.04	Environmental Conditions for Process Measurement and Control Systems: Airborne Contaminants

INTERNATIONAL ORGANISATION FOR STANDARDISATION (ISO)

ISO 9000	Quality management systems — Fundamentals and vocabulary
ISO 9001	Quality Management Systems - Requirements
ISO 10005	Quality management — Guidelines for quality plans
ISO 12944	Paints and varnishes — Corrosion protection of steel structures by protective paint systems — All parts.
ISO 15156 / NACE MR 0175	Material for use in H_2S containing environments in oil and gas production
ISO 5167	Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full - All parts.
ISO 5167	Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full - Orifice plates
ISO 5168	Measurement of fluid flow — Procedures for the evaluation of uncertainties
ISO 5208	Industrial valves — Pressure testing of metallic valves
ISO 7240	Fire detection and alarm systems
ISO 7919-3	Mechanical vibration — Evaluation of machine vibration by measurements on rotating shafts
ISO 10816-3	Mechanical vibration — Evaluation of machine vibration by measurements on non-rotating parts
ISO 12242	Measurement of fluid flow in closed conduits — Ultrasonic transit-time meters for liquid
ISO 17089-1	Measurement of fluid flow in closed conduits - Ultrasonic meters for gas
ISO 17945 / NACE MR0103	Petroleum, petrochemical and natural gas industries -- Metallic materials resistant to sulphide stress cracking in corrosive petroleum refining environments

NORMENARBEITSGEMEINSCHAFT FÜR MESS - UND REGELTECHNIK IN DER CHEMISCHEN INDUSTRIE (NAMUR)

NAMUR NE 21	Electromagnetic Compatibility of Equipment for Industrial Processes and Laboratory
NAMUR NE 43	Transmitters 4-20mA Current Failure Alarm Limits

NATIONAL ELECTRICAL MANUFACTURERS ASSOCIATION (NEMA)

NEMA 250	Enclosures for Electrical Equipment (1000 Volts Maximum)
NEMA ICS 6	Industrial Control and Systems: Enclosures

NATIONAL FIRE PROTECTION ASSOCIATION (NFPA)

NFPA 72	National Fire Alarm and Signalling Code
NFPA 76	Standard for the Fire Protection of Telecommunications Facilities
NFPA 85	Boiler and Combustion System Hazards Code
NFPA 86	Standard for Ovens and Furnaces
NFPA 87	Standard for Fluid Heaters

2.2 ADNOC Specifications

AGES-PH-03-001	Emergency Shutdown and Depressurisation System Philosophy
AGES-PH-03-002 (Part-2)	Fire & Gas Detection and Fire Protection System Philosophy (Part 2 – F&G Detection)
AGES-GL-02-001	Electrical Engineering Design Guide
AGES-SP-04-001	Process Control System Specification
AGES-SP-04-002	Control Valve Specification
AGES-SP-04-003	Fire & Gas System Specification
AGES-SP-04-004	Emergency Shutdown (SIS) System Specification
AGES-SP-04-005	Emergency Shutdown and On/Off Valves Specification
AGES-SP-04-006	Instrument and Control Cables Specification
AGES-SP-04-007	Instrumentation for Packaged Equipment Specification
AGES-SP-05-006	Rotating Equipment Minimum General Requirements and System Integration Specification
AGES-SP-09-001	Piping Design Basis

3 DOCUMENT PRECEDENCE

The specifications and codes referred to in this philosophy shall, unless stated otherwise, be the latest approved issue at the time of contract award.

It shall be the CONTRACTOR's responsibility to be, or to become, knowledgeable of the requirements of the referenced Codes and Standards.

The CONTRACTOR shall notify the COMPANY of any apparent conflict between this specification, the related data sheets, the Codes and Standards and any other specifications noted herein.

Resolution and/or interpretation precedence shall be obtained from the COMPANY in writing before proceeding with the design/manufacture.

In case of conflict, the order of document precedence shall be:

a. UAE Statutory requirements
b. ADNOC HSE Standards
c. Equipment datasheets and drawings
d. Project Specifications and standard drawings
e. Company Specifications
f. Industry / National / International Standards

4 SPECIFICATION DEVIATION / CONCESSION CONTROL

Deviations from this philosophy are only acceptable where the MANUFACTURER has listed in his quotation the requirements he cannot, or does not wish to comply with, and the COMPANY / CONTRACTOR has accepted in writing the deviations before the order is placed.

In the absence of a list of deviations, it will be assumed that the MANUFACTURER complies fully with this philosophy.

5 GENERAL DESIGN DESIGN REQUIREMENTS

5.1 General

The design of automation and instrumentation system, materials and installation shall be in accordance with sound engineering practice. In general, the design and selection of process control and instrumentation systems shall consider the following:

a. Application suitability, reliability, maintainability, quality, accuracy & repeatability.
b. Safety of personnel and equipment during installation, operation and maintenance.
c. Compatibility of environment.
d. System integrity and reliability of hardware and software.
e. Maximum availability of critical equipment.
f. Compatibility with existing instrumentation and systems.
g. Ease of installation, inspection, maintenance and operation.
h. Availability of spares.
i. Flexibility of use.

Main plant instrumentation shall be electronic and contain facilities to communicate with an integrated control and safety control system (ICSS) using one of the following methods:

a. Analogue signals shall be 4-20 mA, 24V DC conforming to IEC 60381 and IEC 60382.
b. Discrete digital signals shall be 24 V DC nominal.
c. Foundation Fieldbus for instruments connected to PCS.
d. Sensors/transmitters shall be ‘Smart’ type with a communication protocol based on HART standard.

e. Valve electro-positioners shall be 'Smart' type with a communication protocol based on HART standard.

f. Switches shall be avoided and used only with COMPANY approval.

g. Fire and gas detectors shall be analogue 'Smart' type with a communication protocol based on HART standard.

h. Buildings shall use an addressable Fire Alarm Control Panel.

Independent sensing instrumentation / transmitters shall be provided for Safety and Control / Monitoring for the same process measurement, and these transmitters shall be specified with the same range and span, with fully independent process connections using separate tappings and located close together to allow comparison of measurements on vessels, equipment or line. Level transmitter tapping points shall be at the same elevation. The transmitters shall continuously cross check to alarm if a transmitter deviates.

Instruments shall be specified with enclosures of classified protection levels in accordance with IEC 60529 and suitable for the environmental conditions in which they are to be located. All field instruments shall be protected to IP65 as a minimum that will meet site environmental conditions, and adequately protected against accident and contact with live or moving parts within enclosure.

5.2 Design Parameters

All Instrumentation provided by the SUPPLIER shall conform to the instrument, electrical, piping, structural, environmental and general design parameters contained within this specification.

SUPPLIER shall only use instrumentation approved by COMPANY.

The SUPPLIER shall be responsible for selection of proper range, and pressure rating, based on fluid properties, operating conditions, and mechanical design constraints for all instruments contained within the package equipment. Note that materials of construction are defined for the intended application with COMPANY approval during FEED and standardised across the asset.

5.3 Environmental / Site Data

Temperature:

a. Maximum Temperature in shade: 54 °C

b. Maximum solar metal Temperature in the sun: 87 °C

c. Minimum ambient Temperature: 5 °C

d. Maximum in Controlled Environment: 55 °C

e. Operating Temperature in Controlled Environment: 22 °C

f. Minimum in Controlled Environment: 0 °C

Relative Humidity:

a. Maximum (at 43 °C): 95 percent

b. Average (at 28 °C): 60 percent

c. Operating (at 22 °C): 55 percent

d. Design: 100 percent

Refer to AGES-GL-02-001 Electrical Engineering Design Guideline for further information.

Note that maximum and minimum temperatures are 58 °C in shade and 4 °C respectively for certain Onshore sites.

5.4 Area Classification

All instrument equipment shall be suitable for the area classification, gas grouping, and temperature classes specified within the project area classification drawings. All field instruments shall be suitable for installation and continuous operation within a Zone 1, Gas group IIB and ignition Temperature class T3 hazardous area as per IEC 60079 as a minimum. Where a more onerous requirement is identified by the facility specific Hazardous Area Classification, then the affected instruments shall meet the more onerous requirements. This shall be verified as a Process Safety Requirement [PSR].

All instrument equipment located in a hazardous and safe areas shall fully comply with Section 7.2.10 and IEC 60079.

5.5 Minimum Design Requirements

Instrument equipment, including accessories, shall be designed, manufactured, tested, transported and installed to achieve a minimum life duration of 15 years with cabling designed for a life of 30 years to allow for at least one major upgrade of the control and instrumentation systems over the design life of the asset.

Wherever possible, the design shall be based upon instruments being returned to the manufacturer for calibration and repairs with whole instruments held as spares. SUPPLIER shall identify these requirements in order to meet the minimum design requirements.

Refer to the following specifications for details on the individual system requirements:

AGES-SP-04-001 Process Control System Specification

AGES-SP-04-003 Fire and Gas System Specification

AGES-SP-04-004 Emergency Shutdown System (SIS) System Specification

5.6 Standardisation

In order to minimise spares, instrument types and simplify the maintenance operations, the number of different instrument SUPPLIER makes, models and types shall be kept to a minimum. Standardisation of instrumentation shall be pursued throughout the project and shall include package equipment instrumentation.

For new builds, all instrumentation and equipment shall be of the same make, model and type as chosen for the project main plant facilities. SUPPLIER shall obtain this information from the CONTRACTOR. Any deviation to this shall require COMPANY approval.

For existing assets, instrumentation and equipment shall be able to interface with the existing equipment and be subject to COMPANY approval.

SECTION B – TECHNICAL REQUIREMENTS

6 PROCESS SAFETY REQUIRMENTS

Where listed within this specification, the term ‘shall [PSR]’ indicates a mandatory process safety requirement.

Sr.No.	Description
1	ESD/SIS Logic Solver shall be highly reliable and certified for safety integrity level of SIL3 as per IEC 61508 and IEC 61511.
2	ESD/SIS Logic Solver hardware architecture shall be redundant and fault tolerant to provide availability of 99.99%.
3	ESD digital output fail-safe state shall be the ‘de-energized’ unless otherwise specified. ESD digital output shall go to a “0” (deenergized) state on shutdown conditions, power failure and on component failure.
4	CONTRACTOR shall carry a Functional Safety Assessment (FSA) as per IEC 61511-1 clause 5.2.6.1.5 prior to the hazards that the SIF are designed to prevent.
5	A detailed safety integrity assessment review to establish SIF integrity targets (SIL) shall be completed by CONTRACTOR during FEED and Detailed Design engineering phase.
6	Once the data is available from selected instrument models, SIL validation reports are to be produced by CONTRACTOR using certified personnel based on the results of the SIL study, demonstrating that the safety instrumented function(s) (SIF)s and safety instrumented system(s) (SIS)s under consideration meet in all respects the safety requirements specification (SRS).

SIFs shall be classified and designed on the following basis:

a. Proper operating, maintenance and inspection procedures are available and adhered to.

b. That Critical spares are available onsite to ensure short turn-around times.

c. The Process safety time for each SIF with SIL greater than or equal to SIL1 shall be provided.

d. All manual ESD hand switches and associated ESD isolation valves used for shutdown / trip shall be considered as minimum SIL 1 functions.

e. Generally, Fire & Gas loops shall be considered as a minimum SIL 1 function. However, for specific critical applications, SIL classifications can be carried out and functions designed accordingly.

f. HVAC air intakes for buildings located in a hazardous area shall be considered as a SIL 2 function.

g. LOPA shall be used for determining the demand rate for all SIFs.

h. For high SIL estimates that are borderline, a more detailed Fault Tree Analysis (FTA) may be required to remove demand rate uncertainties to provide a firm basis for the target SIL.

i. The SIL/PFD targets set in the Front-End Engineering phase shall be verified in Detailed Design phase.

Design shall follow AGES-PH-03-001 ESD and EDP System Philosophy.

PART I

7 DESIGN

7.1 General

The controls of equipment at start-up and in operation will be conducted through the ICSS equipment in Main Control Room (MCR). The shutdown of equipment shall be from MCR and field through the ICSS. Instrumentation and control equipment installed as part of Supplier packages shall be in compliance with ADNOC standards, specifications and philosophies.

The SUPPLIER is responsible for co-operating with the selected ICSS SUPPLIER to have the unit control system implemented within the ICSS without any change in the warranty and performance requirements.

Implementation of package equipment controls in the dedicated package control system offers benefits like full testing at SUPPLIER's shop, minimized site work/ commissioning time but introduces variety in hardware/ software. Utilizing plant ICSS for package controls provides standardization at site and optimizes spares, training, etc.

Accordingly, the package equipment shall be allocated one of the following categories:

a. Package equipment type A shall be fully integrated within the plant ICSS (PCS, ESD and F&G) with all control, monitoring and shutdown functions carried out within the ICSS, with no additional SUPPLIER PLC installed.

b. Package equipment type B shall be fully integrated into the package equipment control, monitoring and shutdown ICSS controllers (PCS, ESD and F&G). The ICSS controllers shall be nodes in the plant ICSS network and supplied as part of the package equipment.

c. Package equipment type C shall be complex packages with PLC control, monitoring and shutdown hardware and shall be fully compatible with the plant ICSS (PCS, ESD and F&G).

To minimise lifecycle cost, the requirement is to integrate as many of the packages into the ICSS (Type A) with the priority being for Type B if Type A cannot be met, followed by Type C if the criteria for the two other types cannot be met. For rotating packages, package type C is not applicable.

All ESD/SIF signals shall be hardwired to ESD/SIS system.

ENGINEER/ CONTRACTOR shall seek COMPANY approval for package category selection.

Refer to AGES-SP-04-007 Instrumentation for Packaged Equipment for further details of the package equipment types.

All instrumentation shall comply with:

a. API RP 551, 552, 553, 554 and 555.

b. Specifications and standards listed in this document

c. Local statutory codes/regulations

d. International codes and standards

All field instrumentation furnished with package equipment shall be of same make, type and model as chosen for the project (main plant), and to ensure standardisation across the facility. SUPPLIER shall obtain this information from the CONTRACTOR, and any deviation to this shall require COMPANY approval.

The SUPPLIER shall furnish all instrumentation that forms an integral part of the equipment or package. This shall include all instruments, controls, interlocks and shutdown devices and circuitry as detailed in this document and the equipment specification. CONTRACTOR shall supply all instrumentation outside the equipment boundary.

The systems controlling the package shall be integrated with the plant control systems by CONTRACTOR. Any Packaged equipment SUPPLIER deviations shall be noted in the quotation.

Implementation of safeguarding functions shall be designed based on the outcome of the SIL study and the category applicable for the package.

The SUPPLIER shall provide engineering and design for the instrumentation, control and safety systems. This shall include specifications and drawings for instruments in the scope of supply and information as required by the CONTRACTOR for the supply of integrated controls. SUPPLIER shall participate in review meetings, HAZOP and LOPA for the Packaged Unit (if applicable) and factory testing as required and coordinated by CONTRACTOR.

The SUPPLIER shall use CONTRACTOR'S specifications, standards, typical hook-ups and drawings. Formats of these shall be provided during Project execution as well as paper copy and electronic media. The same also applies to design instructions.

The SUPPLIER shall be responsible for the end result and for any correction required for a safe and operable unit.

When CONTRACTOR specifies typical schemes in the bid documents, it is the SUPPLIER'S responsibility to examine them and condense or modify them to ensure a safe and operable unit.

In view of the adverse weather conditions at site, the preference is that all outdoor electronic equipment instrumentation (except transmitters, I/P converters) is be located within Instrument Equipment Shelters (IES). The use of field mounted Electronic JB/Remote I/O in safety applications is not permitted. The use of Smart JBs/panel containing Remote I/O and their design shall be subject to COMPANY approval.

For isolation of instruments and drains, refer to the AGES-PH-08-001 Isolation Philosophy.

Each Temperature trip instrument shall comprise of a transmitter with duplex temperature element and thermowell. The transmitter shall have a single 'Smart' analogue output based on average of two elements with configurable difference alarm and element failure alarm. The number of trip instruments required for an application shall be confirmed using the HAZOP and LOPA processes.

7.2 Design Considerations

Maintainability:

a. Equipment that is suitable for unattended operation and supports remote management of maintenance shall be purchased. For instruments other than analysers, the maintenance interval shall be at least 5 years unless otherwise approved by COMPANY.

b. Instrument systems shall be designed and installed to reduce impact on Operations.

c. Instrument design shall not require routine blowdown or other operator intervention.

Cabling and junction boxes shall be designed and engineered to have at least 20% spare capacity at the end of detailed design.

Site location and conditions. Equipment shall be selected for local site conditions:

a. Location onshore, offshore, marine etc.

b. Hazardous area requirements.

c. Climate.

d. Lightning strike probability.

e. Seismic.

f. Transportation to site.

g. Local instrument and equipment supplier support.

h. Equipment shall be selected to minimise lifecycle cost.

i. Designs shall be simple and clearly documented so that:

   i. Installation can proceed to schedule.

   ii. Potential impact to operations and maintenance are understood.

7.2.1 Selection of Instruments

Transmitters shall be 'Smart' type, unless specified otherwise by COMPANY. 'Smart' transmitters shall be based on 4-20 mA DC with the latest version of the HART Protocol. Exceptional cases such as ESD and anti-surge applications shall be reviewed on a case by case basis as the response time to convert the signal makes the instrument too slow to respond in certain applications.

Transmitters used for BPCS can use Foundation Fieldbus.

In general, the package equipment process instrumentation and control system, shall be based on an Integrated Control and Safety System located in air-conditioned pressurized rack and control rooms, and shall be used in conjunction with 'Smart' type electronic transmitters and Positioners. Basic process control, start-up, monitoring and shutdown for main process, utility, off-site areas including the Mechanical Packaged Units shall be through the ICSS or local control. Critical loops shall be defined carefully and redundancy up to field equipment shall be considered for high safety and reliability.

All instruments and instrument systems shall be designed to facilitate first level instrument maintenance and testing. Instrumentation shall be suitable for the process and environmental conditions and designed to cover all operating modes such as start-up/shutdown/emergency operation and pressure relief conditions.

Electronic Transmitters shall be used for all measurements including alarm and trip service, process switches shall be avoided. Where standard mechanical package design includes process switches, COMPANY approval for their use shall be obtained.

Diaphragm seal instruments shall be used on pressure and level instruments in sour service applications. When necessary to prevent corrosive or solids bearing fluids from entering instruments or instrument lines, seals or purges shall be provided. Where diaphragm type seals are most applicable, they shall be given first consideration. Seals or purges should be used in place of heat tracing.

Transmitters shall be SIL certified based on the requirements of applicable SIL classification.

Transmitters shall include diagnostics covering sensor, impulse pipework and electronics and the ICSS I/O module configuration shall comply with NAMUR NE43 (Standardization of the signal level for the breakdown information of digital transmitters) requirements.

Use of local pneumatic control loops shall be subject to COMPANY approval.

All instrument tubing and fittings used on sour service shall be certified to metallurgical requirements of ISO 15156 (NACE MR 0175) or ISO 17945 (NACE MR 0103) and in accordance with AGES-SP-07-003.

All tube fittings shall be double compression type and SUPPLIER shall refer to AGES-PH-04-001 Appendix A1 for Instrument Tubing, Fittings and Valves for use in Sour Service environments.

Unless otherwise specified, the instrument ranges shall be selected such that the normal value will be between 50 and 75% of scale range taking into account the specified minimum and maximum values. Additional instruments may become necessary for normal minimum and maximum values. In these cases, a single scale and auto-ranging facility shall be provided in the ICSS.

Trip setting shall be between 20% to 80% of calibrated range.

For Instruments in ESD Service and for special applications (e.g. Compressor interstage flow measurement for Anti Surge application), a common tapping shall not be used. The exception is for 2oo3 flow measurement using an Orifice assembly where a common tapping is used for multiple DP transmitters, with provision for individual Transmitter isolation and maintenance. Refer to section 8.5.4 for details on meter runs.

7.2.2 Scales and Indicators

Variable	Scale
Temperature	Direct Reading
Pressure	Direct Reading
Flow (Differential)	Direct Reading with square root extraction in Control System.
Flow (Linearized)	Direct Reading
Level	0-100% Linear
Analyzer	Direct Reading
Signal to Valves	0-100%

Local scales for Flow, Pressure, Temperature and Analysers shall be in engineering units and Level scales shall be in “percent“ units unless otherwise specified.

7.2.3 Instrument Accuracy and Range

SUPPLIER shall refer to API 670 Table 1 for the machinery monitoring system accuracy requirements and advise COMPANY of any deviations to these requirements.

7.2.4 Radio Frequency Interference / Electromagnetic Compatibility (EMC)

Protection for EMC shall meet the requirements of IEC 61326 unless stated otherwise in the data sheets.

Non-standard EMC requirements not covered by this Specification shall be identified at the proposal stage.

Supplier’s Quality Plan shall state how Supplier will meet the standards.

Supplier shall:

a. Provide certification of EMC conformance.

b. Confirm equipment is installed in conformance to this Specification and supporting documents required for the installation of the equipment in the scope.

c. Provide supporting information required by Company to verify the installation of the package into the overall plant.

Company will advise Supplier of additional requirements associated with EMC certification.

If EMC conformance is dependent on the installation completed by others on site, documentation, including installation details and specifications, shall be provided so that installation will conform to EMC requirements.

7.2.5 Operation and Design Life

Instrument equipment, including accessories, shall be designed, manufactured, tested, transported and installed to achieve a minimum active life duration of 15 years with cabling designed for a life of 30 years to allow for at least one major upgrade of the control and instrumentation systems over the design life of the asset. Instruments shall be returned to the manufacturer for calibration and repairs wherever possible with whole instruments held as spares.

7.2.6 Environmental Requirements

Other than field local panels (push buttons and lamps), all system cabinets shall be installed in climate controlled unclassified indoor locations.

The indoor installed ICSS shall be suitable for an air-conditioned environment to ISA S71.04, G3 classification. Normal indoor operating conditions will be 22°C ± 2°C and 50% Relative Humidity. The System shall continue to operate in HVAC upset conditions during which in the indoor location of installation temperature can fall to 0ºC or rise to 60ºC, and the humidity can vary between 5% and 95% non-condensing.

The instruments and accessories shall perform to their design specification as per the climatic conditions given below. Sunshades shall be supplied to protect the instruments, accessories.

7.2.7 Electric Utility Data

Power feeds are available from the following sources:

a. Two separate power feeds from the dual redundant 240V AC Uninterruptable Power Supply (UPS) source to provide secure power. The two 240V AC UPS feeders shall not be paralleled unless converted to DC via AC/DC converters to one common DC distribution bus.

b. One feed from the Utility power supply for powering equipment not requiring secure power.

As the ICSS and instrumentation always needs to remain available, the ICSS and instrumentation will be powered from option a.

The Electrical power supply details are as follows:

a. 240V AC, Single Phase, 50 Hz, earthed.

b. Steady state Voltage variation ± 5 % nominal voltage.

c. Steady state Frequency variation ± 2 %.

Refer to AGES-GL-02-001 Electrical Engineering Design Guideline for further information.

7.2.8 Instrument Signals

Instrument signals shall be as follows:

a. Analogue: 4 – 20 mA, HART protocol.

b. Network Signal: Foundation Fieldbus, Wireless, etc.

c. Digital On/Off: 24 V DC.

d. Pneumatic signals: 3 –15 psig.

7.2.9 Seismic Requirements

The system shall be designed to operate in the presence of a sinusoidal vibration of 2g at 10 - 500 Hz and withstand a shock of 15g for 11 milliseconds.

7.2.10 Hazardous Area Protection

Unless otherwise specified, all system and marshalling cabinets shall be installed within a general purpose, non-classified area.

If equipment is located in a hazardous area, the Hazardous area classification and method of protection shall comply to IEC 60079. Equipment located in certified Hazardous Area enclosures shall comply with maximum ambient conditions for continuous operation.

Instrumentation in hazardous areas shall be certified by IECEx or equivalent recognised certifying body. The IECEx directive requires that a register is held of all IECEx certified equipment installed on the facilities and that the equipment is certified to the IECEx 02 scheme in conformance to IEC 60079.

For the UAE, Ex certified equipment also requires an Emirates Conformity Assessment System (ECAS) Ex Certificate of Conformity (CoC) issued by a notified body. Requirement for the ECAS Ex programme utilizes IEC Standards, and qualification of conformity is met by meeting the requirements of the IECEx scheme in full, including mandatory factory site Quality Assessment Reports (QARs).

For instrumentation installed in hazardous area, Ex ia or ib (Intrinsically Safe) design is the preferred method for hazardous area protection. The use of flameproof or increased safety instruments shall be avoided except for solenoid valves which should be certified Ex db (Flame Proof) or Ex mb eb (combined encapsulation and increased safety), operating on 24 V DC with maximum power consumption, of 12W. Ex ia or Ex ib solenoid valves shall not be permitted. Use of Ex ia or ib (Intrinsically Safe) solenoid valves is subject to COMPANY approval.

7.2.10.1 Hazardous Area

The Hazardous Area is defined by hazardous area classification drawings and associated documentation developed by HSE.

7.2.10.2 Hazardous Area Installation

Each electrical instrument or system to be installed in hazardous area shall be built according to IEC recommendations and corresponding national translations and publications.

The local regulations shall have precedence if they are more stringent than the international corresponding code. For each concerned type of instrument or instrument system, the CONTRACTOR shall obtain from the VENDORS (prior to issue purchase order) a copy of the certificate of conformity to the standards delivered by a certified notified body. ECAS certification will be required for equipment used in the UAE.

For all electrical or electronic instruments and systems to be installed in hazardous areas, the hazardous area certification shall be as per IECEx and certification requirements.

7.2.10.3 Instrument Safety Classification

All instrument equipment located in a hazardous and safe areas shall fully comply with latest editions of IEC 60079. SUPPLIER to refer to the project electrical area classification drawings for details of the hazardous and safe area zones.

Unless otherwise specified by COMPANY, the method of protection to be implemented within hazardous areas shall be as follows:

a. Field Instruments
    i. Intrinsically Safe Equipment (Ex ia or Ex ib)
        1. Instrument analogue field devices and valve positioners.
        2. Instrument digital devices.
        3. Limit switches and valve position transmitters.
    ii. Flame Proof Equipment (Ex db)
        1. Solenoid Valves (or dual certified Ex db de).
        2. Gas Detectors.
        3. Fire Detectors.
    iii. Increased Safety Equipment (Ex eb)
        1. Solenoid Valves (Ex mb eb combined encapsulation and increased safety).

b. Junction Boxes
    i. Instrument junction boxes shall be flameproof Ex db as per IEC 60079-1, or Increased Safety Ex eb as per IEC-60079-7, for installation within a Zone 1 or Zone 2 hazardous area.
    ii. Non-incendive Ex n as per IEC-60079-15 shall not be permitted for installation within a hazardous area.

c. Local Panels / Smart JBs
    i. Local Panels / Smart junction boxes shall be flameproof Ex db as per IEC 60079-1, Intrinsically Safe (Ex ia or Ex ib) as per IEC-60079-11 or Increased Safety Ex eb as per IEC-60079-7 suitable for installation within hazardous area.
    ii. Non-incendive Ex n as per IEC-60079-15 shall not be permitted for installation within a hazardous area.

Approved national authorities shall certify all Instruments, instrument equipment, devices or fittings installed in hazardous areas in which it will be used. Additional ATEX marking shall be applicable for equipment conforming to IEC as per European Union Directive, whereas equipment conforming to North American Practices / NEMA shall carry Ex apparatus marking.

Only Active or Galvanic barriers shall only be provided for all Intrinsic Safety (I.S.) requirements, unless otherwise specified in project documents.

Table 7.1 below provides a summary of the guidelines to be used for the selection of instruments and equipment:

Table 7.1 – Safety Classification Guidelines

ZONE 0 Type of Protection	ZONE 1 Type of Protection	ZONE 2 Type of Protection	IEC Reference
Ex 'ia'	Any type of Protection suitable for Zone 0 and	Any type of Protection suitable for Zones 0 or 1	IEC 60079-11
Ex 'sa' (specifically certified for use in Zone 0)	Ex 'ib'		IEC 60079-11
	Ex 'db'		IEC 60079-1
	Ex 'eb', 'ec'		IEC 60079-7
	Ex 'p', 'px', 'py', 'pxb', 'pyb'		IEC 60079-2
	Ex 'sb'		IEC 60079-33

ZONE 20 Type of Protection	ZONE 21 Type of Protection	ZONE 22 Type of Protection	IEC Reference
Ex 'ia'	Any type of Protection suitable for Zone 20 and	Any type of Protection suitable for Zones 20 or 21	IEC 60079-11
Ex 'sa' (specifically certified for use in Zone 0)	Ex 'ib'		IEC 60079-11
	Ex 'tb'		IEC 60079-31
	Ex 'pD'		IEC 60079-2
	Ex 'sb'		IEC 60079-33

Notes:

a. Instruments suitable for installation within Zone 1/21 shall also be suitable for use in Zone 2/22.

b. The IECEx/EC Directive requires that a register shall be held of all IECEx certified equipment installed on the project facilities.

c. Selected equipment protection classification shall be stated on the associated instrument datasheet.

Unless otherwise specified, all instruments as a minimum shall be certified for use in a Zone 1 Gas Group IIB Temperature Class T3 hazardous area.

7.2.10.4 Ingress Protection

The degree of Ingress Protection (IP) for equipment enclosure shall comply with IEC 60529 and equipment data sheets. The equipment minimum IP rating shall be as follows:

a. IP 42 for Indoor climate-controlled environments

b. IP 65 for Outdoor field environments

IEC 60529 Degrees of protection provided by enclosures (IP Code)

Marine exposure shall be considered for all plants. In addition, islands or other locations with sea prevailing winds, shall also take marine exposure into consideration. The protection against corrosion shall include special treatment and coating of all exposed surfaces and the use of corrosion resistant materials and protective housings against corrosive dust and fog.

Refer to appendix A1 for selection of Tubing and Fittings.

7.2.11 Lightning Protection

The standard IEC 62305 Protection against lightning (for electrical, lightning protection is implemented for buildings, MCR and tall structures irrespective of risk based considering the importance of the facility to national economy) shall be used to assess the requirement for protection for onshore and offshore installations.

A risk-based approach to control and instrumentation lightning protection shall be implemented by the Contractor in conformance to IEC 62305-2. The approach shall be documented and agreed by COMPANY.

Surge protection

a. If surge protection devices are required, the extent and location shall be determined, considering issues such as protection of:
    i. Loops that affect critical operations.
    ii. Remote instrumentation e.g. mounted outside a module or steelwork structure.
    iii. Highly exposed instrumentation e.g. at height or on masts.
b. Cabling and field connection technology e.g. Fieldbus shall be considered.
c. Distance between earth points shall be reviewed to determine the voltage likely to be created from a lightning strike.

    Note that it is not necessarily the case that every instrument needs to be protected. A cost-effective solution may mean only protecting main fieldbus trunks and particular vulnerable instruments.
d. Protection may be located at field instruments, in field junction boxes or at marshalling cabinets and may be integral with the equipment or added as separate devices.

7.2.12 Engineering Units

Reference shall be made to Project Engineering Design basis for Units of Measurements.

7.2.13 Air Supplies

Dried, filtered compressed air shall be made available at the dryer outlet at a pressure adjustable between 5.5 barg (80 psig) and 10 barg (140 psig).

Drying facility, filters, and coalescers shall be protected from the effect of surge in the air supply system (for example, on start-up of a standby compressor following a sudden high demand).

The system and equipment shall be designed for the connected loads plus at least 20% at 7 barg (100 psig).

System shall contain storage capacity located downstream of the air dryer designed to maintain air capacity for 15 min after system failure, based on connected load consumption +20%.

Requirements shall be considered for capacity in the event of a failure in conjunction with survivability requirements (e.g. ability to move valves for an extended time after an incident).

Instrument pneumatic supply shall meet the following requirements:

a. At least 5.5 barg (80 psig) pressure at each filter regulator or pneumatic instrument. The operating pressure for instrument pneumatic supply is normally 7 barg (100 psig).

b. Instrument air quality conforming to ISA 7.0.01.

Equipment shall maintain oil content of the air supply below the maximum identified in ISA 7.0.01. This applies to all expected environmental conditions, including high humidity when extensive water dropout is expected.

Use of nitrogen or other medium as an alternative supply to air system shall conform to the following and shall be subject to Company approval:

a. Pneumatic systems in control rooms or other potentially manned areas shall not have nitrogen backups or purges.

b. Nitrogen backup for outdoor local panel pneumatic systems shall be subject to local or regional practices. Instrument air is often used for cabinet purges. Nitrogen backup systems may create a high risk by depleting breathing air in the cabinet. Nitrogen as a backup purge in enclosed areas risks oxygen depletion in the breathing air for personnel who may be present.

An oxygen analyser and low oxygen alarm shall be provided in personnel areas that are purged with an air system having nitrogen as an alternative supply. The low oxygen alarm system shall include:

a. An audible local alarm.

b. A local visible indication.

Signage identifying the unsafe condition shall be included e.g. “Red Flashing Light - Do Not Enter”. Visible indication may be a lamp that is on during normal state and flashes in alarm condition or two lamps (e.g., green for safe, red for not safe).

Instrument air piping shall be sized based on total air consumption for devices on the sub-header and, as a minimum, in conformance to Table 7.2.

Table 7.2 – Minimum Air Supply Line Sizes

Number of devices	Minimum sub header size	
	(DN)	(NPS)
1 to 6	25	1
7 to 14	40	1 1/2

The above specified air sub header sizes are the minimum and shall be evaluated considering the possible dip in the air pressure during simultaneous operation of multiple valves & their air consumption.

Valves requiring an instrument air connection of more than 1/2” (15mm NB) size shall be connected to the main Instrument air header line directly. Such valves are not to be connected to air sub headers.

The system shall be isolatable by unit and sub-unit to allow maintenance outages and reduce air consumption.

Manifolds shall be provided with drain valves.

The units to use shall be selected by the Project.

Branches from the distribution manifolds shall have dedicated valves, each feeding only one user.

There shall be no interconnection between instrument and process air system unless otherwise agreed by COMPANY.

An individual air filter and regulator set with a liquid drain and output gauge shall be installed in the air supply to each instrument.

If pressure reduction is not required for the device, an individual air filter with a liquid drain and valve shall be installed in the air supply.

The design shall include a drip leg with a drain valve on installations prior to the regulator.

By exception and subject to COMPANY approval, a protective device (for example, pressure limiter or relief valve) shall be installed immediately downstream of the regulator set if the following apply:

a. Downstream devices, including local reserve air receiver, are not rated for the main air distribution pressure.
b. Rupture of the main mechanical parts would occur if exposed to full mainline pressure.
c. If there is a hazard due to overpressure and rupture of the instrument downstream of the regulator, that would create a safety hazard to personnel in the vicinity, then a protective device shall be installed.

Connections to instruments shall have sufficient flexibility to allow isolation using a manual shutoff valve and disconnection without disturbing the shutoff valve.

7.2.14 Tropicalisation

Trace heating of instrument systems shall be provided for:

a. Streams that solidify or become highly viscous at ambient temperatures, such as:
    i. Water.
    ii. Streams at risk of hydrate formation.
    iii. Oil with low wax appearance temperature anywhere in the process.
    iv. Oil if the pour point is higher than the ambient temperature.
b. Vapour or gas streams that can condense at local ambient temperatures.
    i. Heating differential pressure instruments and impulse tubing containing volatile hydrocarbons may cause inaccuracies due to difference of head in impulse tubing.
    ii. Vapour or gas streams that may be subject to condensation at ambient temperatures are those in which the ambient temperature is at or near the water or hydrocarbon dew point. Typically examples of these are vapour streams from separators and knock out drums. The shape of the phase envelope and the ambient temperature relative to the process stream temperature are more important than the absolute ambient temperature. Any time the process stream drops below ambient, condensation will occur.
    iii. Avoid heating the liquid in the condensed leg above the boiling point. Boiling temperatures destroy the liquid seal that is necessary to protect the instruments from high temperature and produce unequal levels in the two impulse lines resulting in measurement errors.
    iv. If vapour lines require steam tracing, avoid heating condensed fluids above bubble point in a bend or pigtail, because excessive heat destroys the liquid seal that is necessary to protect the instrument from high temperatures.

c. Sample streams to process analysers, if required.

   i. Trace heating may be necessary to ensure proper conditioning i.e., process impulse line that are low flow and susceptible to freezing.

Instrumentation and instrument tubing that require tropicalisation to properly function, shall be insulated and heat traced.

Insulation shall be designed to be removable and replaceable for repairs, inspection, and calibration of instruments.

Soft insulation blanket kits may be used.

The design of instrument system tropicalisation shall match the heat gain from the tracing to the heat lost to the atmosphere.

Design shall be based on minimum temperature during coldest month of the year and highest wind velocity to be expected to ensure instruments remain operable under the most severe weather conditions.

Diaphragm seals may be used within their pressure and temperature limitations for tropicalisation if seal fluids are selected to withstand temperature at process connection and still maintain fluidity.

Liquid seals shall not be used for tropicalisation. If instruments and lines are self-sealing and if fluid can freeze, heat tracing shall be used.

Purging systems shall not be used to eliminate tropicalisation.

Heat tracing for prevention of solid formation, condensation, or plugging should be electric although steam may be used if available on site and agreed by COMPANY.

Instrument temperature shall be controlled so as not to exceed 120°C (250°F) or supplier recommendations for maximum allowable temperature for the instrument.

Heat tracing shall be designed so the instrument can be removed without disturbing the tracing.

In hot climates, instruments shall be protected by a fibreglass, polycarbonate or metal sunshade which can be removed without disturbing the instrument.

Equipment designed for use in the field shall be protected from direct sunlight and ambient temperatures higher than 40°C (104°F), or the supplier maximum recommended temperature, whichever is lower.

If required, air conditioning systems shall be provided in rooms containing electronic equipment to limit the maximum temperature to 22°C (72°F) or as recommended by the equipment manufacturer.

The operator shall be alerted via the ICSS to indicate failure of air conditioning.

Automatic operation of ventilation louvers on a high differential temperature in case of air conditioning failure shall be provided.

Air conditioning and air change rate of equipment rooms containing battery systems shall ensure safe operation by efficient removal of hydrogen released during charging of lead acid batteries.

Passive cooled shelters may be considered for instrumentation, subject to agreement by Company. A heat dissipation study is to be submitted for Company approval.

Instrument cases shall be light coloured or silvered to reflect heat.

Dehumidifiers shall be provided in equipment rooms if necessary, to meet control equipment specification limits.

Electronic equipment shall be calibrated and sealed in a low humidity environment prior to installation in the field.

Instruments will be tropicalized for humidity and fungus.

Particular consideration shall be taken on all printed circuit boards, even those located in control rooms shall be varnished and electrostatically protected.

CONTRACTOR shall take into account details on storage and calibration of equipment when equipment is unpacked, and that it is stored, temporarily or permanent, in a climatically controlled, air-conditioned environment.

7.2.15 Insulation

Those parts of impulse lines which are filled with high pour-point fluids shall be surrounded by the insulation of the process piping or equipment to keep them at the required temperature.

The traced impulse lines and instrument parts, and all steam supply lines, shall be insulated. All couplings in the tracer tubing and the impulse lines shall be accessible without removing the complete insulation.

For impulse lines, seal pots, steam supply lines, etc., the insulation should normally consist of mineral wool wrapped around and covered with a weather-proof material. The chloride content in the mineral wool insulation shall not exceed 10 mg/kg.

Tubing installed under insulation shall have a high corrosion resistance to avoid having to be provided with a protective coating.

7.2.16 Instrument Enclosure

a. If local instrument performance could be impaired by low ambient temperatures, non-inline instruments shall be housed in temperature-controlled fibreglass or polycarbonate protected instrument enclosures.

b. Inline instruments may be heat traced and insulated, instead of being in enclosures.

c. If enclosures are used for transmitters or gauges the manifold valves shall be within the enclosure.

d. Enclosures shall be sized for the transmitter and manifold to be installed.

e. Process impulse lines shall:

   i. Enter through side or bottom of enclosure.

   ii. Never enter through top of the enclosure.

   iii. Be located to minimise piping requirements.

   iv. Sealed and use bulkhead fittings.

f. Enclosures shall not interfere with the operation of associated valves or nearby equipment, nor obstruct visibility of indicators.

g. Analyser sample systems using pre-insulated tubing shall:

   i. Use heat tracing not in direct contact with process tubing if freeze protection is required.

   ii. Use process tubing of a suitable material, based on the environment in conformance to the Tubing and Fittings requirements.

   iii. Have UV resistant and chloride free jacket material.

   PVC jacketing is not allowed because it contains chlorides which can lead to chloride stress corrosion cracking problems. Other jacket materials such as high-density polyethylene (HDPE) are available. Consult with the tubing bundle supplier for additional guidance.

7.2.17 Protective Coating

Requirements for protective coatings are as follows:

a. Structural materials, equipment, piping and valves shall be supplied in conformance to Supplier's painting specification for a saline marine environment.

b. For outdoor and non-climate-controlled areas, all fabricated supports for Instruments, junction box, trays, panels & metal sunshades shall be Galvanized and painted as per ISO 12944,

   i. suitable for C4 category for non-coastal area

   ii. suitable for C5 category for coastal area

   iii. suitable for CX category for offshore area

c. Refer to AGES-SP-07-001 Painting Specification for details on painting and coating.

d. If Supplier is unable to offer specifications and procedures, or Company assesses Suppliers coating specifications and procedures unacceptable, Company policy shall be used.

e. Suppliers painting specifications and procedures:

   i. Selection of painting system shall be based on minimum and maximum operating temperatures.

   ii. Austenitic Stainless Steel (e.g., 316L type) operating above 50°C (122°F) shall be coated.

   iii. Duplex Stainless Steel and Super Duplex Stainless Steel operating above 70°C (158°F) shall be coated.

   iv. Inspection, testing, and certification shall conform to Company policy.

f. Stainless Steel under insulation shall be coated, regardless of temperature.

g. Method statements from sub-suppliers detailing the procedures and listing the products to be used for surface preparation and coating of the equipment shall be provided to Company.

h. Coating of instruments:

   i. Inline instruments (valve bodies, flow element spool pieces, relief valves, and valve actuators) shall be painted in conformance to Company policy.

   ii. 316L Stainless Steel housing or enclosures of transmitters, instrument PSVs, valve stems and pulsation dampers shall not be painted.

   iii. 316L Stainless Steel junction boxes shall not be painted.

   iv. Stainless Steel tubing and Stainless-Steel fittings operating above 70°C (158°F) shall be painted in conformance to Company policy.

Instruments and the following items shall be protected against paint used on equipment and process units:

a. Glass fronts

b. Moving parts, i.e., control valve stems and positioners

c. Vents and drains

d. Name/data plates

e. Tube fittings and cable glands

f. Isolation and vent valves

Panels and equipment in Control Rooms and Instrument Equipment Shelters (IES) shall be painted so that the dominant type of equipment will determine the colour scheme for the rest of the equipment.

7.3 Isolations

All instruments shall be provided with integral manifold. Close-coupled installation shall avoid impulse tubing and accessories. In such cases direct mounted isolation such as mono block valve shall be used. Each tapping point for the instrument shall be provided with isolation valve to isolate the process line. Isolation valve shall be in accordance with piping material specification. Pressure instrument isolation valve shall be provided with 2-way valve manifold, flow instrument and level instruments (DP type) shall be provided with 5 valve manifold for instrument/ isolation. All drain and vent shall be connected to close/open vent/drain system as appropriate.

7.4 Materials

Materials in contact with process and other fluids shall be:

a. As defined on the data sheets.

b. Confirmed suitable by the Supplier with evidence acceptable to Company.

c. Resistant to corrosive and erosive properties of fluids at pressures and temperatures defined in the project site data. Reference AGES-GL-07-001 Material Selection Guidelines which covers material requirement to mitigate against external chloride stress corrosion cracking in chloride baring environments.

Instrument parts exposed to process fluids containing hydrogen sulphide shall be specified and installed to conform to ISO 15156 (NACE MR 0175) or ISO 17945 (NACE MR 0103) and Management of Hydrogen Sulphide (H_2S) Standard (HSE-OS-ST21).

Flanges assemblies and bolts shall have material traceability certificates and shall be made from materials compatible to the connections.

In line instruments, valves, and thermowell materials shall be specified in conformance to the metallurgical requirements of the project piping specification.

7.4.1 Special Services (Utilities)

In utilities services (such as demineralization plant) strong reducing acids such as hydrochloric and sulfuric acid are often used. For in-line instruments all wetted parts excluding the diaphragm of pressure transmitters, differential pressure transmitters and diaphragm seals shall be Hastelloy B-2 or Hastelloy C-276.

7.4.2 Chemical Plants:

The material selection for pressure transmitters, differential pressure transmitters, pressure gauges, manifolds and impulse lines, etc. is in general related to the material of the equipment and piping. No guidance can be given because of the large variations in products handled. As a general rule, 316 L will be suitable for stainless steel requirements and carbon steel for equipment and piping. In the case of special stainless steel with increased molybdenum content, 6Mo, Incoloy 625 and/or Hastelloy C-276 are applied for the equipment and/or piping, the selected material for pressure transmitters and differential pressure transmitters and manifolds, etc. should be Hastelloy C-276. In all cases, advice from the material specialist shall be sought.

7.5 In-Line Instruments

In addition to the above, the pressure-containing parts of the instruments shall be compatible with the operating conditions. For "in-line" instruments subject to operating pressure, temperature, erosion and corrosion, e.g. orifice plates or positive displacement meters, the selection of materials should be in accordance with the piping class, unless Section 15.8.2 is overruling. In cases where special materials shall be used, this shall be clearly marked on the respective items.

7.5.1 Surrounding Atmosphere

Corrosion from the surrounding atmosphere shall be considered in the selection of materials.

7.5.2 Chlorine Service

The following special requirements of instrumentation on chlorine service overrule, where applicable, other specification:

Filling fluids for capsules and diaphragm seals shall not present a hazard if the diaphragm should fail and shall be selected accordingly. The fluid shall be permanently marked on the outside of the capsule.

7.6 Risk Analysis

Risk analysis shall be performed, and safeguards put in place for instruments meeting both of the following:

a. Tubes or pressure components have a wall thickness less than the process piping wall thickness.

b. Tubes or pressure components are enclosed in a housing in which the design limits of the housing could be exceeded upon failure of any component.

One or more of the following safeguards shall be implemented to mitigate the risk to the target level within the risk analysis:

a. Instrument diagnostics to detect the failure and take action.

b. Alarm to detect the failure and take action.

c. Identify a predicable failure location (e.g. at a specific location on the secondary containment enclosure) to minimise injury. Examples of these are grommets included with pressure gauges or adhesive labels designed for this purpose.

d. Point type monitoring to identify failure (e.g. combustible gas detection, acoustic monitoring).

e. Specification of burst discs or vents on the outer case or secondary containment, to relieve pressure inside the housing and allow material released to be directed away from personnel, environment and equipment.

f. Construction of the outer case or secondary containment as a pressure containing vessel rated for the process design pressure.

g. Risk endorsed by recognised authority.

h. Modifying the housing de rating factor based on supplier testing.

Proposed safeguards shall be subject to agreement by COMPANY.

7.7 Accuracy and Resolution of Measurement

Unless otherwise stated, the minimum accuracy of instruments and closed control loops shall be:

a. Local Gauges: ± 1.0% of full scale.

b. Electronic Transmitters: ± 0.025% of full range.

c. Closed Loop: ± 1.0%.

Instrumentation and installation shall ensure accuracy of measurement in conformance to process and application requirements. Accuracy of the primary element and final element shall be based on the control required by the process to safely operate the control loop or monitor the process.

Accuracy, turndown and range of measurement required shall be specified on data sheets.

The following shall be considered:

a. Normal operation.

b. Abnormal operation.

c. Start up.

d. Emergency conditions.

7.8 Cathodically Protected Pipeline Instrumentation

Above ground instrumentation shall be earthed and insulated from cathodically protected structures.

Earthed tip thermocouples shall not be permitted on cathodically protected systems.

RTD elements on cathodically protected piping shall not be earthed.

Instruments used on cathodically protected systems shall use insulating fittings including insulating flanges, insulated tube unions and earth mats.

Interfaces of dissimilar materials between instrumentation and piping shall be avoided or managed via provision of insulating flange gaskets or dielectric union isolation kit, with the exception of Stainless-Steel instrument fittings to carbon steel piping.

Dielectric tube fittings shall be specified in cathodic applications if electrical current flowing through a pipe or tube line will be interrupted to protect vital instrumentation and metering equipment.

Dielectric fittings use non-conductive materials as an interface to prevent electrical current flow. The dielectric fittings shall be selected to prevent material incompatibility.

8 FIELD INSTRUMENTS

8.1 General

8.1.1 PCS Transmitter Requirements

Transmitters shall be H1 FOUNDATION™ Fieldbus Protocol or 4-20 mA with HART.

High-speed digital (less than 10 millisecond scan) or analogue transmitters shall be used if a fast response is required for the process.

Typical high-speed applications are surge control and pipeline leak detection.

Most digital transmitters are not recommended for very fast loops, or to initiate switching if fast response times are required.

8.1.2 SIS Transmitter Requirements

Inputs to the SIS shall be through continuous analogue measurement devices, switches shall not be used.

Transmitters shall:

a. Transmit 4-20 mA with HART analogue signal proportional to input range.

b. Meet or exceed the performance requirements in the safety requirement specification (SRS).

Transmitters for SIS service shall conform to one of the following:

a. Certified by a third-party competent accreditation body to conform to IEC 61508-2.

b. Have a "prior use" justification in conformance to IEC 61511-1 using the method provided by COMPANY.

Supplier shall provide an analysis of failure modes for the device. Failure mode analysis shall be performed by an independent third party, in conformance to IEC 61508.

Transmitters used for trip shall:

a. Be separate from transmitters used for measurement, control, and alarm purposes.

b. Use separate process tappings, particularly if impulse lines can become blocked (plugged). If shared tapping is used, common mode failure shall be included in PFD calculations.

c. Each trip function shall use a separate transmitter to avoid common mode failure.

Inferred measurements as the only measurement to achieve an integrity level requirement of 1 or more shall not be permitted.

Examples of inferred measurements include:

a. Level calculated from mass balance.

b. Oxygen concentration calculated from operating conditions.

SIF and PCS transmitters measuring the same process parameter shall have the same range.

Transmitter fault values shall be set to match the SIS logic solver values as transmitters have internal diagnostics which set transmitter outputs to pre-determined mA values if a fault is detected. SIS related transmitters shall have fault values based on the NAMUR NE43 standard (i.e. fault indicated by signal of less than or equal to 3.6 mA or greater than or equal to 21.0 mA).

Sensor selection to meet specified SIF response times shall allow for process delay at the point of measurement.

8.2 Pressure

8.2.1 General

Pressure instruments shall conform to transmitter and pressure instrument clauses of Process Measurement Instrumentation and Miscellaneous requirements.

Relief valve set pressure and accumulated relief pressure for the system shall be covered by:

a. At least one pressure instrument input to the ICSS or main panel.

b. All pressure gauges.

At least one pressure transmitter on each system shall measure to 10% over system design pressure.

8.2.2 Transmitters

Purges may be fitted on heavily fouling tapings to avoid blockages.

Purges shall not constitute the only metallurgical protection on highly corrosive duties.

If purge supply pressure can vary by more than ±10%, continuous purges shall be controlled by a constant differential relay. Tubing downstream of the relay shall be run in a continuous length. Constant differential relays maintain a constant DP across a built-in needle valve to maintain a constant volumetric flow rate. Continuous tubing avoids leaks.

For tubing applications, the piping and instrument interface shall be specified with a flange tube adaptor (with integral compression fitting) and the instrument end shall be either:

a. Manifold with integral compression fitting, or.

b. Kidney flange with integral compression fitting bolted to manifold.

8.2.3 Gauges

A pressure gauge with a metallic case shall be specified if steam or electrically heat traced.

Dials for special service gauges shall have graduated scales selected from the standard ranges. Gauges shall have pointers with micro zero adjustment.

Draught gauges may use a quadrant illuminated edgewise indicator.

Water gauge U-tube manometers may only be used for testing and on heaters to measure draught.

Ranges shall be selected so that the pointer reads approximately 12 o'clock at normal operating pressure. Maximum working pressure of a gauge shall not exceed 65% of the full-scale value for fluctuating pressure or 75% of the full range value for steady pressure.

A diaphragm sealed gauge or overpressure protection may be used if the measurement range is low.

Safety pattern gauges with solid front and blowout protection shall be used on all process applications, including:

a. Duties above 25 barg (365 psig).

b. Applications with flammable process fluids above 10 barg (145 psig).

In toxic service gauges shall be avoided.

8.2.4 Differential Pressure

Low pressure side of the differential pressure instrument shall withstand full line pressure without damage.

Differential pressure transmitter installations shall have a 5-valve integral manifold with drain connections piped to a suitable safe location for the application.

Dry leg design shall be used for the low-pressure side. Manufacturer shall confirm device specification if an elevated or suppressed option is being considered.

Transmitters shall be mounted above line on gas service and below line on liquid service unless otherwise agreed by COMPANY.

For applications measuring differential pressure across exchangers or in columns:

c. Transmitters shall be mounted above the upper tap to ensure free draining into a vessel.

d. Impulse lines shall be:

   i. Run using tubing and fittings.

   ii. Run with the shortest, most direct, vertical path using 45-degree bends. There shall be no horizontal sections or other places where condensed material can collect. Non-vertical sections shall have the greatest gradient practical.

   iii. Traced and lagged, if process conditions require.

Glycol, silicone, or white oil may be used as seal liquids where the low-pressure leg of a differential pressure instrument is exposed to vapour service that is subject to condensation or liquid entrapment.

8.2.5 Pressure Switches

Switches shall not be used on pressures less than 25 mbarg (0.36 psig).

Switches shall not be used with over range protection devices.

Pressure switch accuracy and dead-band requirements shall be determined for each switch application.

The use of pressure switches is subject to Company approval.

8.2.6 Diaphragm Seals

Diaphragm Seal shall normally be integral with the instrument. The application of diaphragm seals with capillary extensions shall be kept to an absolute minimum.

Special attention shall be paid to diaphragm seals on low differential pressure and pressure applications.

Applications of diaphragm seals with capillary extensions require the written approval of the COMPANY.

When a diaphragm seal is required, the largest practical size should be applied as specified in the data sheet. Special coating materials may be considered where these will improve the corrosion resistance of the diaphragm.

The capillary tubing material shall be of type 316 stainless steel and be shielded by flexible stainless-steel tubing, according to MANUFACTURER'S standard.

The length of capillary tubing shall suit the application, but the length should be at least 1.0 metre. For differential pressure applications the capillary tubing shall be the same length.

If process fluid is liable to separate, solidify or deposit in impulse lines one of the following options shall be used:

a. Diaphragm seals. Using diaphragm seal type connections prevents plugging of the instrument due to solidification of the viscous material, freezing, or settling of solids.

b. Purged or trace heated impulse lines with advanced diagnostics such as plugged line detection.

Diaphragm seals shall be used if providing instrument impulse lines with process compatible materials is impracticable.

Liquid filled diaphragm seals shall be selected for the following:

a. Fouling duty such as slurries.

b. Purged or trace heated impulse

c. Boiling services.

    i. Viscosity greater than 0.30 Pa s (300 cP) at 16ºC (60ºF).

    ii. Corrosive.

    iii. Contaminated or dirty fluids.

Pressure loss effect of diaphragm seals shall be allowed for in instrument calibration if the pressure to be measured is below 2 bar (30 psi).

Seal materials shall be selected to conform to the following:

a. Temperature and pressure ratings.

b. Resistance to corrosion.

c. Toxicity of liquid fill.

Remote diaphragm seals shall be connected to the pressure instrument by armoured stainless-steel capillary tubing.

Capillaries shall be specified to the correct length to avoid the need for coiling, as short as possible to reduce temperature effects and response time.

Larger ID capillaries may be specified to improve time response or smaller ID capillaries to improve temperature response.

Supplier shall be consulted to provide guidance about capillary length based on specific applications.

Diaphragm seals shall have a flushing or calibration ring (also called a drip ring) between the process isolation valve and the diaphragm seal.

The standard size for the diaphragm seal used with pressure transmitters shall be 50 mm (2 in) to ensure accurate transfer of pressure and resolution.

Fill fluid shall be specified so that it does not freeze or become viscous at ambient temperatures.

Table 8.1 provides a range of fill fluids, but the device supplier shall make a recommendation based on process and environmental conditions.

Note that Silicone Oil DC200 and DC704 are most commonly used.

Table 8.1 – Diaphragm Seal Fill Fluids

Fill Fluid Types	Temperature Limits at Atmospheric Pressure	Viscosity at 25 °C (77 °F)	Specific Gravity at 25 °C (77 °F)
Silicone 200 (DC-200)	-45°C to 205°C (-49°F to 400°F)	9.5 mm^2/s (9.5 cSt)	0.934
Silicone 704 (DC-704)	0°C to 315°C (32°F to 600°F)	39 mm^2/s (39 cSt)	1.07
Syltherm XLT Silicone	-73°C to 149°C (-100°F to 300°F)	1.6 mm^2/s (1.6 cSt)	0.85
Silicone 705 (DC-705)	20°C to 350°C (68°F to 662°F)	175 mm^2/s (175 cSt)	1.09
Inert (Halocarbon)	-45°C to 160°C (-49°F to 320°F)	6.5 mm^2/s (6.5 cSt)	1.85
Neobee M-20	-15°C to 225°C (5°F to 437°F)	9.8 mm^2/s (9.8 cSt)	0.94
Note: The temperature rating above is based on capillary mounting. If direct mounting is used, temperature rating will be reduced.			

The fill fluid for oxygen service shall be a Chlorotrifluoroethylene, such as Fluorolube or equivalent.

Compatibility of seal fluids with process fluids shall be verified and fill fluids shall be selected to prevent contamination of the process fluid.

Seal system shall be filled by the pressure instrument supplier.

8.3 Temperature

8.3.1 General

Temperature instruments shall consist of an element and transmitter, either head mounted or for local, field mounting, supplied together.

Elements shall be installed in thermowells so as to be removable during plant operations, with the following exceptions:

a. Embedded mineral insulated sensors used to measure bearing, motor or generator winding temperatures.

b. On air conditioning systems, unless removable without dismantling equipment.

c. Skin temperatures of heater, reactor internals or boiler tubes measured by direct contact sensors.

In these cases, there is a requirement to seal the process from the environment. This shall be achieved with a compression fitting. In certain applications (for example, reactor bed temperature), it may be necessary to pass the sensor through a special isolating shear valve so that if a compression fitting fails, process isolation can be achieved. In such cases, design to ensure the temperature sensor does not drop into the process. This may require the use of a special probe with a reduced diameter tip.

Circuit shall be IS if sensors are installed without a thermowell and the process fluid is potentially flammable.

Standard thermowell and element lengths shall be used to minimise spares holding.

Surface mounted temperature measurement in safety application shall have at least 50 mm (2 in) of insulation fitted around the sensor with 500 mm (20 in) insulation on either side of the sensor.

For application where temperature measurement is required to detect a loss of flow, the installation shall be left un-insulated such that heat loss to the surroundings is maximised and accepting the loss of measurement accuracy.

RTD or thermocouple measurements connected via IS barriers or galvanic isolators shall take into account increase in measurement uncertainty. Galvanic isolators degrade the measurement uncertainty of the loop. Even leakage currents in “low leakage” Zener barriers degrade the measurement.

Transmitter range shall be selected so that normal operating temperature is within middle third of the range.

Dual element sensors shall be used. Use of dual elements allows the user to switch connecting wires from one element to the second element or use dual input transmitters without removing the sensor assembly from service, if the first element fails or requires verification. Dual element sensors shall not be used for both PCS and ESD circuits from the same element.

Specification of surface temperature detectors shall be approved by Company.

Qualified welding procedures for vessel and pipe skin thermocouple half coupling shall conform to requirements defined for the mechanical installation.

Skin thermocouple installations used to detect vessel shell temperatures shall have 1 boss for every 2 m^2 (20 ft^2) of vessel surface.

Washer type or magnetic thermocouples may be installed for temporary installations on vessels or pipe.

8.3.2 Resistance Temperature Detectors

Resistance Temperature Detectors (RTD) elements shall be 3 wire duplex type unless 4 wire is required for custody transfer measurement, housed in a mineral insulated 6 mm (1/4 in) nominal OD 316 Stainless Steel sheath. The RTD elements shall normally be of the 3-wire platinum type, 100 ohms at 0°C tolerance Class A in conformance to IEC 60751. Nominal resistance at 0°C shall be 100 Ohms with a temperature coefficient, α equal to 3,851 x 10-3 °C-1.

8.3.3 Thermocouples

Thermocouple extension wires shall conform to IEC 60584, Part 3 or API RP 551.

Thermocouple design shall be a mineral insulated, duplex thermocouple in a 6 mm (1/4 in) nominal OD 316 Stainless Steel sheath with the junction earthed to sheath unless there is insufficient space in which case a 3mm (1/8 in) diameter may be used. An earthed junction provides improved response time over an isolated junction. An isolated junction may make both installation and earthing systems easier, since multiple earths are less of a problem.

For earthed thermocouples, the input channel of transmitters or input cards shall not be earthed.

For differential temperature measurement, two thermocouples shall be:

a. The same type connected in opposition into one measuring instrument.

b. Isolated junction type.

For temperature averaging, two or more thermocouples shall be:

a. The same type.

b. Unearthed.

c. Connected in parallel.

Thermocouples may be considered as an alternative to RTD in high vibration service.

Thermocouple elements should be in conformance to temperature ranges shown in Table 8.2.

Table 8.2 – Thermocouple Element Temperature Ranges

Type	Thermocouple material	Normal temperature range °C (°F)	Standard tolerance (a) °C (°F)
E	Chromel constantan	–200 °C to 0 °C 0 °C to 870 °C (–328 °F to 1600 °F)	±1.7 or ±1% ±1.7 or ±½%
J	Iron constantan	0 °C to 760 °C (32 °F to 1400 °F)	±2.2 or ±¾%
K	Chromel alumel	–200 °C to 0 °C 0 °C to 1260 °C (–328 °F to 2300 °F)	±2.2 or ±2% ±2.2 or ±¾%
R	Platinum 13% rhodium platinum	0 °C to 1480 °C (32 °F to 2700 °F)	±1.5 or ±¼%
S	Platinum 10% rhodium platinum	0 °C to 1480 °C (32 °F to 2700 °F)	±1.5 or ±¼%
T	Copper constantan	–200 °C to 0 °C 0 °C to 370 °C (328 °F to 700 °F)	±1.0 or ±1.5% ±1.0 or ±¾%

Note:

a. The tolerance expressed in °F is 1.8 times larger than in °C. If tolerance is in %, the % applies to the temperature being measured expressed in °C.

b. The Normal operating temperature range is the operating range within the standard tolerance.

8.3.4 Thermowells

Thermowell pressure and temperature ratings, testing and certification requirements shall be compatible with applicable piping or vessel specifications.

Potential operating and flow conditions shall be considered during the mechanical design of the thermowell such as high flow and high or low pressure associated with start-up, shutdown, process upsets and pressure relief conditions.

The element sensitive length and internal thermowell bore shall match and provide an immersion length so that accurate measurement is achieved.

Unless measurement would be adversely affected, thermowells shall be mounted into pipes, rather than process vessels.

Threaded thermowells shall be by exception and subject to Company approval.

Pipe diameter for thermowell installations shall be at least DN 80 (NPS 3) unless otherwise agreed by Company.

Thermowell nozzles in piping shall be installed in conformance to piping specifications.

Thermowell installation shall allow immersion between 1/3 and 2/3 of the internal diameter of the pipe, elbow or tee.

Follow the ASME PTC 19.3, TW-2016 for calculations of natural frequency and corresponding frequency limits.

The use of collars is not permitted.

Immersion length may be reduced to optimise the design for high fluid velocity rating and low stresses subject to agreement of Company. This may result in reduced accuracy and/or delayed response. A deviation needs to be raised to manage such a change.

In vessels, thermowells shall have an insertion length of at least 440 mm (16 in).

In columns, thermowells shall be immersed into liquid. Alternatives shall be subject to approval by COMPANY.

Thermowells and elements shall be selected to ensure that the tip of the probe is in firm contact with the end of the thermowell bore.

Special thermowells or elements installed without thermowells shall be subject to approval by Company.

Special design shall be provided for:

a. Fast response.
b. High fluid velocities where helical designs can be used to control flow induced forces and vibration.
c. Measurement of reactor bed temperatures.
d. Installation in lines smaller than DN 80 (NPS 3). Installation of the thermowell shall be either on a bend or tee or in a section expanded to 3” diameter for smaller pipe sizes.
e. Analyser installations.
f. Installation in ducts or flues.
g. Corrosive or erosive service.
h. Retractable thermowells.

Use of spring-loaded probes to measure skin temperature on reactors is not preferred due to spring failure potential as a result of exposure to heat over time. Manufacturer shall be consulted for such requirement.

8.3.5 Temperature Switches

The use of switches is not permitted and can be used only with prior COMPANY approval. Where use of switch is approved, the following shall be applied within the design:

Temperature switches shall have adjustable set points or adjustable differential span settings marked with a reference scale.

Temperature switches shall be activated by either thermocouples or RTDs if:

a. Switch trip point accuracy requirement is ±1% or better.

b. Overall control scheme is electronic design.

c. Power supplies are available.

Temperature switches shall have snap acting type actuation devices. Temperature switches that have snap acting type actuation devices are preferred over switches with lever, volume, or piston type mechanisms. This is because the snap acting type provides better accuracy and repeatability of set points.

8.4 Level

Selection and installation of level measuring devices shall be such that:

a. Device selected is of the required accuracy and not over specified. Generally, accuracy to better than ±2% of span is needed only for fiscal transfer level measurements.

b. Resolution of level indication shall be 1% or better.

c. Measurement is reliable and reproducible.

d. Installation is designed for maintenance device calibration.

e. Clearance for device removal and maintenance are provided.

f. If the vessel will not be available for maintenance, the measuring devices are installed with provision for isolation to enable online maintenance and testing. Avoid devices installed directly in vessels if possible.

Consideration shall be given to seasonal influences on the accuracy and reliability of the measurement, including:

a. Fluid density changes.

b. Fluid freeze point.

c. Risk of hydrate formation or similar.

d. Fluid vaporisation.

Continuous level measurement shall be used instead of level switches except if agreed by Company.

Float switches shall not be used except if agreed by Company.

Level transmitters shall be specified to work at atmospheric pressure in addition to the process design conditions.

Level devices and connections, including floats, shall be pressure rated to the full test pressure of the associated vessel or 150% of MAWP.

Guided wave radar (GWR) / displacer (if GWR is unsuitable for the process media and condition) shall be used for interface liquid level measurement.

For special applications, the differential type level transmitters may be mounted on a Bridle along with the level gauge glasses. Level switches for noncritical alarms and noncritical interlocks may also be Bridle mounted, along with the differential level transmitter and level gauge glasses. For more critical applications, level transmitters may be directly connected to the vessel. For ESD applications, the level transmitters shall be mounted on separate vessel nozzles. For voting (ESD) applications common Bridle shall not be used.

Preferably for most applications, e.g. for level measurements at the side of a drum, the guided wave radar transmitter may be mounted on a Bridle along with the level gauge. Level transmitters for PCS indication, noncritical alarms and interlocks may also be Bridle mounted, along with level gauge. For ESD applications, each level transmitter shall have independent nozzle connections.

For liquid-liquid interface service (e.g. water boots on vessels), GWR type transmitters and transparent type level glasses, each directly connected to the vessel shall normally be used. The use of bridles in liquid-liquid interface shall be minimized but may be considered where multiple level devices are required, and the temperature differences between the vessel contents and the bridle contents will not cause measurement error.

For flare drums service, GWR shall be facilitated with dynamic vapour compensation to automatically compensate for dielectric changes.

Each GWR level transmitter shall be installed with adequate isolation, vent and drain valves for test and maintenance purposes.

8.4.1 Storage Tank Level Measurement

Tanks shall generally have separate level measurement instruments with temperature and pressure to calculate average density as required for tank gauging.

Independent Over Fill protection shall be provided based on HAZOP / SIL recommendations and as per API 2350 requirements.

On tanks where automatic overfill protection is mandated, dedicated SIL certified level transmitters shall be implemented.

It shall be possible to link temperature and density measurements into this system. Tank level indicators shall be provided with stilling well, isolation valve, and calibration chamber as per VENDOR'S recommendation.

At least three temperature points and a density measurement shall be provided per tank.

Guided wave radar shall be used for interface liquid level measurement. Guided Wave Radar (GWR) shall also be considered in place of Displacer type wherever the application allows use of both.

8.4.2 Operating Range

The range of the level device shall be set so that:

a. 100% indicated level is reached before the vessel is full.

b. In process vessels typically 10% of the vessel volume remains available above the range of the device. Actual level needs to be able to go above the operating range without overfill issues being an immediate problem.

If a vessel has the potential to overfill the worst-case measurement error shall be used and included in the calculation of range, alarm point and trip points. Overfill may have undesired consequences including a potential relief valve lift.

Additional over range requirements shall be considered.

Measurements based on differential pressure, density, conductivity or similar physical properties shall be ranged to allow for variation in composition of liquid and gas phases. Level measurement methods can demonstrate significant errors.

a. Range of continuous level devices shall be at least equal to the full operating requirements of the actual level, including start-up requirements and abnormal operating states.

b. If more than one level device is needed for the full operating range, display to the operator at the ICSS shall provide 0% to 100% over the full operating range. Display cannot read 0% to 100% for each device.

c. If more than one device is installed measuring the full operating range, the devices, including gauges, shall have identical measurement ranges. Where more than one level instrument is required to cover the full range for each application, there shall be an overlapping measurement range to ensure that the entire range is covered without any break.

d. If level switches are installed, continuous devices shall operate over a range that is at least equal to that covered by the switches.

8.4.3 Redundancy and Diversity

Aim to reduce common cause failure as much as practical by device selection e.g. use of a DP cell and GWR device will reduce common cause failure created by unexpected foaming of the fluid or changes in fluid density.

a. If multiple devices are installed, as part of a SIF, each shall have separate nozzles.

b. Control and alarm nozzles shall be separate from nozzles for SIFs. Installation on existing plant shall be subject to company approval.

c. If multiple level devices are required (a control device, a second for an alarm or potentially several devices as part of a SIF), diverse level technologies may improve overall reliability.

8.4.4 Mechanical Connections and Piping

Vessel connections shall conform to process and mechanical specifications.

Thread connections shall be avoided on toxic or flammable service.

Vessel branch sizes to external standpipe and chamber shall be:

a. At least DN50 (NPS 2) for all devices.

b. Minimum DN 80 (NPS 3) for GWR devices.

Vessel connections directly at the bottom of the vessel shall not be permitted unless approved by Company. Bottom vessel connections are to be only used where absolutely necessary. Adding a drip leg can help but that will typically plug. Purging and other techniques that add maintenance will be needed to achieve accurate level measurement.

Connections to level device chambers shall be side entry.

For instruments requiring alignment with vessel nozzles, Contractor shall ensure:

a. Checks are carried out of dimensioned drawings of instrument, vessel and standpipe if applicable, though-out the design process.

b. Checks are made at inspections of instruments, vessels and standpipes if applicable. Dummy instruments or spool pieces can be used for this. Laser alignment can also be used.

Standpipes and chambers shall be mounted vertically to a tolerance not exceeding ±1 degree.

If measurement line drains are required by the level technology, these shall be routed to the correct drain location for the fluid.

Closed drains shall be used for toxic and flammable fluids, unless agreed by Company. Typically, small volumes from 5 valve manifold vents and purge rings are drained to local receptacle whereas larger volumes in standpipes and GWR spools are drained to the closed drain system.

8.4.5 Standpipes (Bridles)

Standpipes with multiple instruments attached may be used. They reduce the need to provide multiple vessel taps and the associated valves.

A single standpipe shall not be used for all control, alarm, local indication and trip devices.

Design shall take into account:

a. Maintenance purges, multiple standpipes and other non-standpipe-based measurements shall be used where there is a potential for blockage. In the event of a blockage all level devices attached to a standpipe will fail at the same time creating common cause failure event. The risk is significant where the fluid contains particulates, has a tendency to polymerise, forms extensive hydrates or could freeze.

b. Bridles shall be avoided where a temperature difference between the vessel liquid and the standpipe cannot be overcome with the use of insulation. The density difference may be such that the fluid in the vessel is above the fluid indicated by a non-density dependent level device installed on the standpipe.

c. Need for additional tappings to ensure accurate measurement of interfaces. 3 tappings are required, one at the bottom of the bottom liquid phase, one in the top liquid phase and one in the gas phase. It is essential that at least one nozzle is in each liquid phase. Where the interface level can vary multiple tappings may be required to ensure this is the case under all process conditions. Consider also a need for venting any gas which could accumulate in the standpipe and cause an error.

SIL calculations shall include the blockage frequency of the standpipe and nozzles.

Standpipes shall:

a. Be self-draining throughout the measurement range.

b. Have low point drains and high point vents if required.

c. Not have a diameter less than 50 mm (2 in).

Trace heating requirements of the standpipe shall be considered.

Horizontal lengths of the standpipe shall be kept to a minimum and where in excess of 1 m (3 ft), supports shall be provided in conformance to project piping specification.

8.4.6 Prevention of Liquid Overfill

Independent Over Fill protection shall be provided based on HAZOP / SIL recommendations and as per API 2350 requirements.

On tanks where automatic overfill protection is mandated, dedicated SIL certified level transmitters shall be implemented.

High level alarms, required by a LOPA towards the mitigation of a hazardous vessel overfill, shall be positioned to provide at least 10 minutes remaining fill time, above the switch before overfill. Process safety times are subject to Company approval.

High level alarms shall not be set above 90% of level span or density compensation of the level measurement shall be provided. If the level signal changes as a function of density, calibrate the level device assuming the lowest density with which the device operates, including fluid density at start-up.

8.4.7 Supporting Calculations

Detailed level sketches shall be provided showing the following:

a. Physical installation, including distance between taps and vessel dimensions.

b. The zero, span, alarm and trip points.

c. Specific gravity of process, including upper and lower fluids for both liquid to liquid and liquid to gas interfaces.

d. Fill fluids and their specific gravity.

Level sketches shall indicate tolerances because of fluid variations such as density or conductivity.

8.4.8 Differential Pressure (DP) Cell

If measurement leg is liquid filled, as preparation for use, the fluid selected shall be compatible with the process fluid and of similar density.

If the process fluid crystallises, or solidifies, liquid filled leg shall not be permitted.

Trace heating shall be provided on liquid filled legs where there is a risk of fluid freezing or hydrate formation.

DP transmitters shall have vents and drains to facilitate calibration and test unless remote seals are used.

Connections shall not be made to a process line that has a fluid velocity. This practice is seen on retrofit type installations in which a vessel tapping is not available and creates a measurement error, increasing as the fluid velocity and pressure drop increases.

The DP cell shall be located as close as practical to the bottom tapping point. The longer the length, the greater the risk of blockage.

Minimum operating pressure range shall be specified as 0 barg (0 psig) to allow for blowdown.

DP cell shall be mounted level with bottom tapping if practicable. If this is not possible, mounting below bottom tapping should be used instead of mounting above.

If the DP cell is not level, the zero-calibration point will require adjustment. The required adjustment shall be specified on the instrument data sheets.

If DP cell is mounted above bottom tapping:

a. DP cell may be mounted up to a maximum of 300 mm (1 ft) above the bottom tapping,

b. A continuous fall between the cell and the isolation valve shall be provided. This method reduces the risk of measurement line blockage but has the disadvantage of creating a minor error on the displayed measurement.

If the low pressure leg is operated liquid full, fill points shall be provided.

If there is potential for condensation in a dry low pressure leg, heat tracing shall be provided. Overfill bends shall be provided for all dry low pressure legs. This method helps prevent liquid build-up in the low pressure leg both from condensation and in the event of the liquid being above the top tap.

If impulse lines require gas purge:

a. Transmitter shall be installed with a condensation or overfill bend at least 1 m (3 ft) high in the low-pressure measurement leg.

b. Purge supply lines shall run in a vertical direction, down into the measurement lines.

c. Purge velocity shall be approximately 200 mm/s (8 in/s). If velocity is too low, the purge is ineffective. If too high, the purge creates an unacceptable measurement error.

d. Purge flows shall be approximately equal to help balance measurement error due to flowrate pressure drop.

e. Purge systems shall have a variable area flowmeter and needle valve for flow adjustment.

f. Purge systems operating at greater than 10 barg (140 psig) shall use a Stainless Steel variable area flow meter.

g. If a “Bubbler” type level measurement is used, design shall ensure that associated pressure drops do not create an unacceptable measurement error.

h. Protection against reverse process flow on purge failure shall be prevented by a non-return valve.

i. Purge shall not be used as a protection against corrosion of the measurement lines by the process fluids. Purges are provided to enable a reliable level measurement. They are not an acceptable method to prevent measurement line corrosion. (i.e., selection of metallurgy is also be compatible with process fluids). If used to enable the transmitter to be mounted above the vessel, loss of purge results in a zero-level measurement. Operators are to be made aware of this.

j. Purge shall not be specified as a substitute for measurement line trace heating.

If impulse lines are liquid purged:

a. Purge supply lines shall be run horizontally into the measurement lines.

b. Purge velocity shall be in the region of 20 mm/s (0.8 in/s). If velocity is too low, the purge is ineffective. If too high, the purge creates an unacceptable measurement error.

c. Protection against reverse process flow on purge failure shall be prevented by a non-return valve.

Diaphragm seals shall be considered if:

a. Measurement lines are subject to blockages.

b. Low pressure leg will not operate continuously, wet or dry, with confidence.

c. Fluid is corrosive to the extent that no cell metallurgy is technically available.

Diaphragm seal systems shall be based on high pressure seal close coupled to transmitter and low pressure seal connected by capillary unless this arrangement is not practical and then only by agreement of Company. This represents a tuned system and minimises capillary temperature effects on the accuracy of the instrument.

Diaphragm seal capillaries shall:

a. Have a length that avoids coiling of the capillaries.

b. Be kept to a minimum practical length.

c. Have fill fluid selected to account for fluid temperature at operating conditions.

Diaphragm seals shall:

a. Have gold plating on high pressure hydrogen service.

b. Be contained within an all-welded DP assembly on vacuum service.

DP transmitters may be used to measure level interface if the fluids have a density SG difference of more than 0.1.

8.4.9 Displacer

Tolerance on measurement shall take into account SG changes.

Displacers shall be:

a. As a minimum, 316 Stainless Steel grade material or as required by the process fluid.

b. Completely submerged.

c. Designed for the density of the process fluid.

d. Designed to withstand the full test pressure of the vessel.

e. Calibrated assuming the lowest likely density of fluid present during operating regimes, including start-up.

Displacer to head connection shall be glandless.

Length of displacer shall not exceed 1.5 m (5 ft).

Displacers shall not be used:

a. Internal to the vessel on continuous processes.

b. If isolation and depressurisation of the vessel cannot be achieved.

If internal stilling wells are used, they shall be perforated type.

Displacer chamber shall have fill and empty connection valves to enable calibration.

8.4.10 Surface Float

Floats shall be installed with a stilling well or external chamber including tanks with little fluid disturbance.

Floats shall:

a. Be designed for the density of the process fluid.

b. Operate below the top connection.

c. Withstand the full test pressure of the vessel.

8.4.10.1 Servo Type

Servo-type tank gauging shall be the latest microprocessor-based Tank Level Management System using 2-wire full duplex or Ethernet communication link. The system shall be able to provide signals to the ICSS for remote indication and alarming purposes. It shall be possible to link temperature and density measurements into this system. Tank level indicators shall be provided with stilling well or guided as per VENDOR'S recommendation.

Facilities and isolation methods shall be provided to fully withdraw the float from the operating area of the vessel or tank, enabling inspection of the float with the vessel in full service. Generally, this is achieved by a combination of a full-sized ball valve and tee piece viewpoint. The float is withdrawn into the tee piece and ball isolation is operated. The tee point then can be used to remove the float, if required.

A secondary alarm from the device shall not be considered fully independent as a prevention of vessel overfill.

The device shall be installed with a fixed datum point to enable in situ calibration.

At least three temperature points and a density measurement shall be provided per tank.

A separate hardwired and independent overflow alarm for floating roof tanks shall be provided.

8.4.10.2 Float and Tape

Float and Tape type of level gauge shall only be used for local indication on non-hydrocarbon tanks where specified.

8.4.11 Radar Level Transmitters

There are two types of radar level transmitter that may be considered mainly:

a. Non-Contact Radar type

b. Guided Wave Radar type

In general, the use of radar type level transmitters shall be carefully evaluated prior to adoption.

8.4.11.1 Non-contact radar

Storage tanks that require high accuracy of measurement may use non contacting radar.

Non-contact radar shall be avoided on vessels that have active process conditions (e.g. separation towers, steam drum, separators, reflux drums, and similar).

Vapour space shall be transparent to radio frequency. No rain, steam, condensation, etc. shall be present.

If the fluid is turbulent, the device shall have a stilling well or external chamber, with the chamber being preferable.

Stilling wells:

Note Stilling wells provide an amplified return surface signal that allows for a more accurate level representation.

a. Perforations shall be lined along the length of the stilling well to provide a stable measurement surface within the well.

b. A reflector plate shall be installed at the bottom end of the stilling well, unless manufacturer recommends this is not necessary. The method ensures a clear zero level measurement is achieved when the vessel is empty.

Applications with low dielectric constants, less than 2.0, shall have a standpipe (external) or stilling well (internal).

Wells shall be supported throughout their length, every 3 m (10 ft) or as determined by a detailed mechanical stress analysis.

Antenna shall be installed parallel to the well or chamber within a tolerance of ±1 degree.

Antenna selection:

a. Beam sweep for antennas located in stilling wells shall be concentrated within the well and shall be analysed to avoid conflict with well or chamber surface.

b. Antennas shall be selected to minimise:

   i. Build-up of condensation (e.g., flat antennas are susceptible to condensation build up) or solids.

   ii. Loss of signal due to the use of coatings (if required) or contamination of the antenna.

Facilities and isolation methods shall enable removal of the device with the vessel in full service. The method shall be a recessed installation with a full port ball valve and through piping to avoid measurement conflict with piping accessories.

The non-contact radar shall be installed with a fixed datum point to enable in situ calibration.

To check correct function, a fixed partial beam obstruction may be added to the vessel. Failure to see the obstruction or change in position is a fault.

If a combination of low dielectric and dense vapour space exist, e.g. LPG, the manufacturer shall be consulted to ensure the device is applicable.

Non-contact radar supplier shall demonstrate and verify track record in successful application of the device selected for LPG level measurement.

Stilling wells shall be used for LPG service.

Non-contact radar level transmitters shall be mounted on the top of the vessel or on an external chamber. Depending on the dielectric, frequency, antenna, design, etc, the maximum measuring range runs from 3 metres to 45 metres. Accuracy shall be 0.1% of span or better.

Non-contact Radar is an effective technique and considered for the following services:

a. Dirty / Slurry service
b. Corrosive liquids and gases
c. Extremely viscous or coating liquids
d. Scale forming services
e. Varying density, dielectric or conductivity
f. Below ground vessels and enclosed sumps

Limitations

a. Products with dielectric constant between 1.4 and 2.0 when a stilling well is used
b. Products with dielectric constant >2.0 a stilling well is not used
c. Do not use when vessel has internals that may block or reflect the pulse
d. Do not use when fluid surface is agitated or when foam may be formed

8.4.11.2 Guided Wave Radar (GWR)

GWR device shall be selected and the installation designed in consultation with the supplier.

An internal stilling well or external chamber shall be used to increase the return signal and ensure a stable level measurement surface. Contractor shall ensure the arrangement is agreed by the selected supplier.

Coaxial type probes can be difficult to clean on dirty services and shall be avoided.

Technology that allows full analysis of the return signal (i.e., echo curve or spectra analysis) shall be specified.

Interface measurements shall take into account the dielectric constant and height of both layers to configure the device for the application.

At high operating pressures, changes in the dielectric constant of the vapour space shall be considered. Compensation methods and their limitations shall be reviewed. Water or steam is an example. At pressures above 50 barg (725 psig), pressure compensation is to be considered. In some cases, above 100 barg (1450 psig), a total loss of signal is likely.

Flexible GWR elements shall be considered for extended measurement lengths beyond 2 m (6,5 ft), at which a rigid probe is vulnerable to bending or damage. The flexible probes shall be coupled with anchoring accessories that provide rigidity throughout element length.

Probe anchoring accessories shall be used where lengths exceed 0.5m (20 in).

If the intended application operating environment has turbulence and rapid level changes, rigid and flexible probe types shall be anchored in conformance to manufacturer requirements.

Internal stilling well:

a. Internal GWR installations shall be installed with a stilling well (referred to as "top mount") immersed into a product storage tank, vessel, or column. The stilling well provides concentrated signal propagation and increased surface echo return for increased accuracy and measurement stability.

b. Design and fabrication of stilling well shall be in consultation with the GWR supplier.

c. Internal stilling well shall conform to vessel codes and regulations.

External chambers:

a. Shall be a minimum diameter of 75mm (3 in). Chambers with a smaller diameter may create spurious signal reflections.

b. Shall include provisions for the isolation and testing of the GWR.

c. Shall conform to vessel codes and regulations.

d. Fabrication methods shall incorporate the supplier requirements.

e. Shall be fabricated with manufacturer's defined spacing between probe and interior chamber wall.

f. Shall provide measurement span equal to the span between top and bottom connection nozzles.

g. Chamber installation shall conform to isolation methods for removal of the device with:

    i. The vessel in full service.

    ii. Installation of vents.

    iii. Drains for device calibration.

    iv. Testing.

    v. Maintenance.

h. A device shall be selected that enables detailed spectrum analysis of return signal.

i. Use of coatings on the probe (often PTFE) shall conform to manufacturer's recommendations to prevent build up on the probe or antenna.

j. Dual probe devices shall be avoided. Dual probes have a tendency to foul between the probes and bridging becomes possible.

k. If GWR is used on a vessel that is non conducting, earthing methods shall be agreed with the supplier of the GWR.

GWR is the preferred liquid level and liquid-liquid interface level measurement technology for both process and instrumented protective systems applications where the dielectric constant is greater than 1.4 for the measured fluid.

For normal interface applications there should a dielectric difference >=6 with the upper surface having a dielectric <=10 and there should be a distinct interface between the two liquids.

GWR requires use of Coaxial, Twin rod or Single rod wave guides that are immersed in the process fluid. Twin and single rod guides may be used only where high viscosity or dirty service dictate. Co-axial radar instruments may be considered for clean, non-corrosive liquids.

Any 'dead zones' on the wave guide probe shall be designed outside the operating range of the GWR instrument. In any case, process level shall not enter in probe's dead zone. For pressurized process vessels, probes shall be flange mounted in external bypass chambers. GWR bypass chamber material shall meet the application requirements and shall be steel construction as a minimum. Chamber connections on the top, bottom or sides shall be 2 inch flanged.

GWR shall be 4 -20 mA, HART based 'Smart' transmitters with integral indicator. These transmitters discharge energy directly into the process and shall have their sensor electronics certified for the hazardous area classification inside the vessel.

GWR electronics heads/housings shall have the capability to be removed from their associated wave guide probe assembly.

Measuring performance:

a. Accuracy ± 5 mm or better;

b. Repeatability ± 1 mm or better;

c. Ambient Temperature effect: Less than 0.01% of measured distance per ºC.

8.4.12 Sonic Technology (Ultrasonic Level Measurement)

Sonic technology shall not be used:

a. On pressurised vessels.

b. As the only form of liquid overfill protection, including if used on floating roof storage tanks.

Contractor shall include errors and compensation methods if changes in the pressure of vapour space create measurements errors.

If installed on pits or similar, open path devices shall be shielded from rain and impact.

8.4.13 Capacitance

Dielectric properties of the fluid for operating conditions shall be confirmed as being within manufacturer specifications before selection. Capacitance level instrument accuracy is a function of the liquid dielectric constant. Care is to be taken to determine the dielectric constants of the fluids being measured over their full range of possible compositions and operating conditions.

The method of initial testing and routine proof testing shall be agreed by COMPANY.

Capacitance devices shall not be used as the only measurement preventing liquid overfill.

Device manufacturers recommendation for vessel earth method shall be followed.

Support shall be provided for devices longer than 1 m (3 ft) mounted on the top face of the vessel vertically down into the process.

8.4.14 Nuclear - Gamma-Based Technology

8.4.14.1 Radiation Safety

Contractor shall conform to procedures provided by Company on management of radioactive materials in the region.

Radioactive sources shall conform to local codes and comply with regulations in effect at the site of the plant, for manufacturing, packing, transportation, installation, operation, and maintenance.

Contractor shall:

a. Ensure that the latest local codes have been reviewed and requirements are implemented.

b. Carry out and record a justification for use of nuclear devices over other technologies.

These codes and procedures will provide:

a. A maximum annual dose, which is outside the control of the Contractor.

b. A limit for the dose rate representing the maximum allowable rate outside a controlled area.

Sources shall be limited to a dose rate lower than this value at the outside surface of the source storage enclosure or as defined in the code.

A source storage enclosure shall be provided:

a. In compliance with the local regulatory body.

b. Enabling full source isolation.

c. For internal sources, which shall be withdrawable into the source holder.

To avoid stray radiation, external source holders shall have collimation designed to restrict the radiation to the operating angle required by the detector.

Where there are several nuclear detectors and associated sources in the area the installations shall be aligned to ensure no cross contamination occurs.

A fireproof source holder shall be specified, based on the failure mode and consequence in the event of a fire.

Source holder labelling shall comply with local regulations.

Vessels with nucleonic instruments shall have warning indicators (e.g., signs and colours complying with regulatory agency requirements) installed near the source holder and at man-ways.

Source holder shall incorporate a lockable source isolation method for locking the shutter in place. “Open, Shut” indicator flags shall be clearly legible.

Scintillation crystals or plastics should be used if the device manufacturer offers a choice.

Weight of the source holder shall be used during design of the mounting brackets and supports.

Design shall include detailed dimensions for the support for holders and detectors so that the vessel design and support structure can be checked and measured to ensure correct fit.

A dummy source holder may also be provided so that the installation can be checked during construction.

Vessel insulation shall:

a. Be compatible with the source and detector configuration.

b. Not compromise the radiation safety.

c. Gaps between the source and vessel shall be closed to prevent access.

8.4.14.2 Measurement guidance

Source size shall allow at least 10 years of operating life.

Caesium 137 should be used as the preferred source type.

Cobalt 60 may be needed for duties with thicker vessels or long flight paths.

Type of source, source strength, and type of mounting shall be determined by agreement with the supplier. The following factors shall be considered:

a. Vessel size.

b. Gamma flight path.

c. Wall thicknesses.

Specification may be based on initial design wall thickness for vessel.

Final vessel details shall be used to confirm specification of the device.

Process conditions including:

a. Range of pressure from atmospheric to design pressure.

b. Density of vapours throughout this pressure range.

Location of source and detector.

Accessibility and maintainability.

Required range.

Ease of linearisation.

Source decay compensation shall be provided if recommended by device manufacturer.

Detector shall enable the raw counts to be available.

Detector shall be set with a count integration time of no greater than 15 s and shall achieve a worse case accuracy of ±5% of span.

Alarm points shall conform to this accuracy. The device is likely to remain repeatable after calibration and line fit. The error expected is most likely to be noted at high level, with the zero being an easy calibration point. In the worst case, flat lining early becomes likely at 95% indicated level.

If used on high pressure duties, compensation of the level measurement for changes in vapour pressure shall be provided.

If several level detectors are required on a single vessel and vapour pressure compensation is used, the pressure measurement device shall be redundant to minimise common cause failure of the level system.

Redundant detectors shall be provided if required but the provision of source redundancy shall be avoided. A single source for several detectors e.g. continuous, point or profiler, may be used.

If extreme foaming is likely, additional tolerance shall be made on the alarm and trip setpoints to allow for the error produced. Methods for compensating for foam shall follow the manufacturer's recommendation. The heaviest sustainable foam throughout the span may create a 5% level measurement with no level present. The error is flight path length and case by case dependent and can be discussed with the supplier. Solids attached to the inside of the vessel are likely to result in a significantly high-level measurement.

Insulation material shall not be installed between the source and detector.

Location shall be chosen to avoid obstruction by major steelwork.

8.4.14.3 Nuclear Profiler

Note: Generally, a profiler is installed internal to the vessel. The method is subject to various patents. The method uses many point source detector pairs in a vertical array. Each detector source pair provides a density measurement in its simplest form, providing a clear liquid vapour transition point. Density of the fluid present at each pair also is provided. The method has temperature and cost limitations that limit widespread use. Calibration of the device usually provides little benefit.

The design of the profiler installation in the vessel shall be agreed by the manufacturer.

Consideration should be given to supporting the profiler if it is longer than 1 m (3 ft).

Profiler shall:

a. Comply with local legislation for the source holder design.

b. Provide zero external dose level outside of the vessel.

Resolution shall be 1% or less.

Entire system shall be pressure rated to at least the test pressure of the vessel.

Wetted materials shall be compatible with the fluids present, 316 Stainless Steel as a minimum.

If required to allow coverage of the full range, vessel design shall accommodate any dead band at the bottom of the profiler by e.g. addition of a boot.

8.4.14.4 Nuclear - Backscatter

Backscatter shall be:

a. Considered only if other nuclear techniques cannot be applied.

b. Used only for point level measurement.

Portable devices shall not be used.

8.4.15 Surface Float - Magnetically Coupled to the Transmitter

Transmitters shall be magnetostrictive (preferred) or resistance chains.

Transmitter shall be fitted with vibration isolators.

Facilities for draining and venting shall be provided. The dominant failure mode is the transmitter fails to track the float. To simply test the transmitter is not acceptable.

8.4.16 Switches

The use of level switches are subject to Company approval.

8.4.16.1 Surface float

Float type device shall not be used for a SIF.

Provisions shall be made for testing and maintenance of level switches.

Float type switches shall be mounted in external chambers except if:

a. Vessel is close to atmospheric pressure.

b. Float can be tested using the process level directly (e.g., storage tanks and water break tanks).

Top fill and bottom drain facilities shall be provided.

Drain shall be routed to a safe location.

External level switches with flanged block valves that are installed directly on vessels shall have flanged process taps.

Floats shall:

a. Be designed for the density of the process fluid.

b. Operate below the top connection.

c. Withstand the full test pressure of the vessel.

d. Have integral stops provided to limit the angle of float travel, located as near as possible to the float.

e. Switch shall have hermetically sealed double pole, double throw type switch contacts.

f. Float to switch connection shall be glandless.

8.4.16.2 Tuning fork (electromechanical)

Tuning fork switches may be used for prevention of tank overfill, if assessed and certified.

A level switch installed to prevent liquid overfill of a hazardous fluid shall be a vibrating fork switch in conformance to IEC 61508, unless otherwise agreed by Company.

Provisions shall be made for the testing and cleaning of the tuning fork switch without production loss.

The preferred mounting orientation for powder or viscous fluid service shall be vertical or angled down at 45 degrees.

Support shall be provided for switches longer than 1 m (3 ft) mounted on the top face of the vessel vertically down into the process shall be supported.

A spool extension may be used to make a tuning fork switch retractable.

8.4.17 Gauges

8.4.17.1 Gauge Type Selection

Preferred gauge method shall be float type with magnetic wafer display system.

Glass tube type gauges shall not be used except in very limited applications and if a magnetic follower type is not suitable, with agreement of COMPANY.

Need for the following shall be determined:

a. Level of NDT required (e.g., X-ray, dye pen, or Positive Material Identification (PMI)).

b. Heat tracing (potentially if liquids can solidify).

c. Coating protection (e.g., offshore epoxy, general protective, or natural).

Corrosion allowance shall be determined.

The level coverage specified for gauges shall allow the operator to verify correct operation of level instruments and manually operate the equipment.

On equipment without level controls, gauges shall cover the entire operating level range.

If level range is greater than allowable gauge length, additional nozzles or external standpipe may be used.

Gauges shall have a scale in mm, cm or inches marked over the operating length.

Level instruments located at the bottom of vessels and gauge columns shall have clearance for installation of drain valve and associated piping.

8.4.17.2 Magnetic Level Gauges

Float, flanges and chamber shall be 316 Stainless Steel grade material as a minimum or as required by the process fluid.

On a carbon steel vessel, standoff allowance (centre line of chamber to the face of the flange mating the vessel) shall ensure that the float is not unduly affected (approximately 150 mm [6 in] standoff). This technology should be avoided in process systems made predominantly from carbon steel materials. There is a tendency for iron deposits to collect on the wall of the chamber, which can prevent the float from moving.

Large diameter Magnetic Level Gauge (MLG) chambers (75 mm [3 in] to 150 mm [6 in]) shall be considered, with a standard size float and a float biased system in carbon steel systems.

Guidance on operating or testing procedures shall be documented so that they do not involve rapid pressurisation of the float chamber.

Vent valves shall not be quarter turn or other types which allow rapid opening. Damage and failure of the float can occur if the chamber is pressurised at speed, the float can be rammed to one end of the chamber.

Float stops shall be provided at each end of the chamber consisting of a spring fitted with a carbon or PTFE buffer, as required by process conditions.

MLG may be used for interface measurement if the density of the fluids is such that the float weight can be selected to float at the interface.

If used on interface a third nozzle (approximately midpoint between centres) shall be provided to ensure both fluids can enter and leave the chamber.

If used on interface, the float shall be designed to remain completely submersed in fluid. An SG difference of 0.2 is generally needed. Less than 0.2 is possible, but the float length can quickly become very long (in excess of 1 m [3 ft]). In such cases, the float may become stationary, top or bottom, even if the interface is moving.

GWRs and MLGs may be specified as a combined chamber.

A colour scheme shall be used for recognition of the interface level from the overall level.

Maximum length of single gauges shall be 3 m (9.8 ft). Multiple gauges should be used for ranges greater than 2 m (6.6 ft).

Intermediate mechanical supports shall be considered.

Design pressure rating (at maximum temperature of service) for gauges glass shall be at least 1.5 times the maximum operating pressure of the service.

Magnetic level gauges shall be provided as first choice unless not suitable for the application. The design shall ensure that the magnetic properties of the applicable parts of the magnetic level instruments shall not degrade under the influence of design temperature given in data sheets. Magnetic Level gauges shall be provided with ¾" NPT Vent & Drain connections.

Magnetic Level Gauges offer advantages like enclosed metallic construction, suitability to severe service conditions and availability of longer lengths. These gauges consist of a metallic chamber, float and indicating scale. The chamber shall be of non-magnetic material like stainless steel. Floats shall be bottom-insert type with provision for removal during maintenance, inspection. Float stop springs shall be provided at the top & bottom side of the gauge to avoid damage. Process connections shall be 2” flanged with “side – side” type configuration.

Specific gravity shall be specified in the data sheets for design of the float. Due consideration shall be given in the design as stainless-steel gauges would be installed on carbon steel vessels. Design shall facilitate easy removal of float and trouble-free operation for given service conditions.

An engraved measurement scale, installed adjacent to the indicating chamber, shall be provided. This scale shall be corrosion resistant type and the colour of engraving shall be as specified in the data sheet. The orientation of measurement scale shall be site adjustable to any angle without any additional hot work / welding. Frost extensions shall be installed on Magnetic Level Gauges with an operating temperature of 0°C or less.

Glass type level gauges may still need to be used due to boiler code requirements.

8.4.17.3 Glass Through or Reflex Level Gauges

Note This section is included for completeness if glass gauges are approved by COMPANY for the application.

Reflex glass level gauges may be used on the following services:

a. Clean, non-viscous fluids that are not corrosive to glass.

b. Saturated steam pressures up to 32 barg (464 psig).

Through vision (or transparent) type gauge glass may be suitable for use on the following services:

a. Interface duty. Reflex gauges cannot detect a liquid interface.

b. High viscosity fluids.

c. Acid or caustic.

d. Saturated steam of 21 barg (305 psig) to 120 barg (1740 psig).

Bicolour transparent LLGs may be used on high pressure saturated steam of 70 barg (1015 psig) to 100 barg (1450 psig).

Through vision and reflex gauges shall have toughened, borosilicate glass in conformance to at least one of the following specifications:

a. BS 3463.

b. DIN 7081.

Design pressure rating (at maximum temperature of service) for gauge glass shall be at least 2 times the maximum operating pressure of the service or 1.5 times flange pressure rating. This safety factor is necessary, because gauge glasses may be subjected to repeated thermal and pressure cycling that fatigues materials over a long period.

Gauges on services below ambient temperatures may require non-frosting blocks if there is potential for build-up of frost or ice. Illumination external to the gauge may be required for certain applications.

If non-frosting blocks, manufactured from a static holding material, are to be used in an IECEx zone, they shall have antistatic earthing.

Gauge bodies shall be designed so that the glass sits in a shallow recess, allowing for thickness of sealing joint.

Shield shall be used to reduce glass deterioration if process conditions require:

a. Plastic (KEL-F®) for acid type duties.

b. Mica for steam and pH 8.0 and above in which product can attack the glass.

8.4.17.4 Connections and Valves

Gauge glass valves shall be angle pattern, offset design with bolted bonnets, complete with vent and drain valves for internal gauge cleaning.

Gauge glass valves shall have excess flow internal ball checks with knockoff devices.

Valves that are directly connected to vessels shall have flanges.

If duty is on hot or corrosive fluids, gauge valves (straight through or offset) shall be OS&Y type unless the immediate environment around is more of a corrosion issue, when internal threaded shutoff valves shall be used.

Top and bottom (end to end connected) gauge connections shall be used, except if agreed by COMPANY.

If threaded connections are used:

a. Reflex and transparent gauge glasses shall have DN 20 (NPS ¾) female end connections.

b. Vessel connections for gauge glasses shall be at least DN 25 (NPS 1).

If additional clearance for the vessel or other equipment is required, a spool piece shall be installed between the gauge valve and the primary block valve.

8.5 Flow

Note: Measurement systems for Class 2 flow will have commercial agreements associated with them and this is to be defined by the project in conformance to these agreements, as defined by Company.

Measurement systems shall be designed in conformance to the ADNOC Metering guidelines and Project specifications.

Industry standards, technical reports and guidance notes shall be consulted, along with the manufacturer's installation recommendations.

The design of upstream straight length requirements, flow conditioners, and filtration shall take into account presence of a second phase or fluid component, and where deposits on instrument internals, transducers and flow conditioners could occur. The pressure drop associated with flow conditioners and filters may cause the appearance of a secondary phase when fluids are close to phase equilibrium. Long straight lengths could allow stratification of two component flows.

Static head at the instrument relative to the gas-liquid interface shall exceed dynamic head of the liquid. This is to minimise the presence of free gas in liquid metering downstream of a phase separation vessel.

Liquid flow pipe runs shall be mounted below phase equilibrium interfaces to avoid gas break-out. This implies that the separator produces fluid in equilibrium, which is not always the case since the retention time of mini or two-phase separators may not be sufficient for all free gas to come out of solution. Gas breakout may be avoided by designing the facility, offshore platform or process module building, with the liquid metering located on a lower floor than the process vessel. It may be necessary, for certain critical accounting or allocation applications, to consider the use of a pump in the liquid metering stream to boost pressure in order to avoid inaccuracies being caused by the presence of free gas.

8.5.1 Differential Pressure Devices

Selection table of differential pressure devices is given below:

Primary Element	Application									Measurement characteristics				
	Gas (vapour)		Liquids											
			Non-slurries				Slurries		Steam					
	Clean	Dirty	Clean	Viscous	Dirty	Corrosive	Fibrous	Abrasive		Available sizes DN (NPS)	Accuracy (1)	Rangeability	Type of output	Re
Concentric orifice plate	A	NR	A	LA	LA	LA	NR	NR	A	≥50 mm (2 in)	±2-4%	8/1	Sq Rt	> 10 000
Quadrant edge orifice plate	NR	NR	A	A	LA	LA	NR	NR	NR	≥50 mm (2 in)	±2-4%	8/1	Sq Rt	> 200 < 10 000
Segmental orifice plate	LA	A	LA	LA	A	LA	LA	LA	NR	≥100 mm (4 in)	±2-4%	8/1	Sq Rt	> 10 000
Eccentric orifice plate	LA	A	LA	LA	A	LA	LA	LA	NR	≥50 mm (2 in)	±2-4%	8/1	Sq Rt	> 10 000
Integral orifice plate	A	NR	A	A	NR	LA	NR	NR	A	≤40 mm (1½ in)	±1-3%	8/1	Sq Rt	> 10 000
Conditioning orifice plate	A	NR	A	LA	LA	LA	NR	NR	A	≥50 mm (2 in)	±1-2%	8/1	Sq Rt	> 10 000
Compact orifice flow meter (concentric plate)	A	LA	A	LA	LA	LA	NR	NR	A	≥15 mm (½ in) ≤300 mm (12 in)	±1-2%	8/1	Sq Rt	> 10 000
Flow nozzle	A	LA	A	LA	LA	LA	NR	NR	A	≥50 mm (2 in)	±1-2%	8/1	Sq Rt	> 10 000
Venturi tube	A	LA	A	LA	LA	LA	LA	LA	A	≥50 mm (2 in)	± 1%	8/1	Sq Rt	> 75 000
Averaging pitot tube	A	NR	A	NR	LA	LA	NR	NR	LA	≥25 mm (1 in)	±3-5%	3/1	Sq Rt	> 4 000
Cone	A	A	A	A	A	LA	LA	LA	A	≥15 mm (½ in)	±1-3%	10/1	Sq Rt	> 500
Turbine flow meter	NR	NR	A	NR	NR	LA	NR	NR	LA	≥8 mm (¼ in)	± ¼% of rate	20/1	Linear	>5 000 (3)

Primary Element	Application									Measurement characteristics				
	Gas (vapour)		Liquids							Available sizes DN (NPS)	Accuracy (1)	Rangeability	Type of output	Re
			Non-slurries				Slurries		Steam					
	Clean	Dirty	Clean	Viscous	Dirty	Corrosive	Fibrous	Abrasive						
Positive Displacement flow meters	LA	NR	A	LA	NR	LA	NR	NR	NR	≤300 mm (12 in)	± ¼-½% of rate	10/1	Linear	> 100 (4)
Variable area meters	A	NR	A	LA	LA	LA	NR	NR	LA	≤80 mm (3 in)	±2-10%	10/1	Linear	No limit
Magnetic flow meters	NR	NR	A	A	A	A	A	A	NR	≥15 mm (½ in)	± ¼% of rate	30/1	Linear	No limit
Vortex shedding meters	A	LA	A	NR	LA	LA	NR	NR	A	≥15 mm (½ in) ≤300 mm (12 in)	± 1%	10/1	Linear	> 15 000
Ultrasonic Flow Meter (UFM) - Transit time	A	NR	A	LA	LA	A	NR	NR	NR	≥15 mm (½ in)	±1-5% ±½%	20/1	Linear	No limit
- Doppler	NR	NR	NR	LA	A	A	A	A	NR	≥15 mm (½ in)		10/1	Linear	No limit
Thermal flow meters	LA	LA	LA	LA	LA	LA	NR	NR	LA	≥8 mm (¼ in)	± 1%	10/1	Linear	> 8,000
Coriolis meters	A	LA	A	A	A	A	A	A	NR	≥6 mm (1/8 in)	± 0.1%	50/1	Linear	No limit

Legend:

A - Applicable, H - High, L - Low, LA - Limited application, M - Medium, NR - Not recommended

Notes:

1. Accuracy in percent of span uncalibrated unless specified (including transmitter).
2. Measurement characteristics should be checked against supplier data. This table should be used only as general and broad guidance.
3. Turbine meters suitable for low viscosity applications: 2-15 cSt
4. Positive displacement meters suitable for applications if viscosity ≤8000 cSt

8.5.2 Flow Orifice with Differential Pressure Transmitters

Electronic differential pressure transmitters shall be solid state strain gauge, or capacitance, diffused silicon or semi-conductor type.

The DP transmitters shall be 'Smart' type. Besides 4-20 mA signals, transmitters shall use HART protocol for digital communication with ICSS.

In general, the square root extraction (linearization) of the flow signal shall be carried out in the transmitter except for specific sites already having the implementation in ICSS and special applications like anti-surge loop).

The DP transmitters shall have integral field indicators; otherwise remote indicators shall be supplied and installed in the field next to the associated Control Valve as per licensor's recommendation. Independent meter shall be used for shutdown/tripping services.

Any flow compensation and totalization of electronic DP transmitter's signals shall be implemented on the ICSS.

All instruments shall have over-range protection up to the maximum permissible static pressure of the instrument.

Use of liquid filled seal type instruments requires COMPANY approval.

The body and all wetted parts in contact with process fluids shall be a minimum of 316 Stainless Steel unless service conditions require higher metallurgy. In any event, the metallurgy selected shall be fit for the intended use and subject to COMPANY approval.

Material selection for DP transmitters shall comply to NACE standard ISO 15156 (NACE MR 0175) when fluid contains H_2S or when specified in the piping class.

Based on a square root scale or chart reading of 1-10. the flow meter shall be ranged for a reading at:

a. Maximum flow between 9.0 and 9.8 of the scale
b. Normal flow between 7.0 and 7.5 of the scale
c. Minimum flow not below 4.5 of the scale for flow meters used in accounting, material balancing and alarm or tripping services.
d. Minimum flow not less than 3.0 of the scale for other services.

Where requirements are conflicting, ultrasonic meters with higher rangeability shall be used after obtaining COMPANY approval.

In addition, Stacked DP transmitters shall be selected for different ranges to minimize uncertainty while maximizing rangeability for a given orifice plate. Refer API MPMS 14.3.2 for further details.

Transmitters, or secondary instruments that sense differential pressure generated by flow through an orifice primary device, shall be mounted as follows, unless otherwise approved by COMPANY:

a. Below the process line if:
b. The fluid being measured is liquid.
c. The fluid is steam or a condensable vapour.
d. Only below the process line if a vapour will stay in the liquid phase.
e. Above the process line if the fluid being measured is dry gas or noncondensing vapour. Differential transmitters are normally mounted below the orifice in liquid service and above for gas and vapour. For condensing vapours, the transmitter may be mounted below, and the impulse lines liquid filled. Some

examples are; Silicon 550 insoluble in water for steam and condensate service, Glycol for light hydrocarbon and Flurolube FS-5 for Alkylation plant service.

Sensing lines and fittings shall be welded if required by process and mechanical specifications.

Pairs of impulse lines shall be as short as possible and of equal length. Pairs of impulse lines shall be run together to prevent density discrepancy between them, even if lagged.

For remote transmitter installations where liquid is susceptible to freezing or waxing, trace heating protection shall be provided to prevent freezing of sensing lines and transmitter.

For ease of maintenance and calibration testing, differential transmitters used with orifice plate installations shall have a 5-valve integral manifold.

8.5.2.1 Orifice Plate

In general, orifice plates shall be the primary measuring device for differential pressure instruments. Measuring elements shall be designed as recommended by ISO 5167 (PART 1, 2, 3 & 4) and 5168 standards. Orifice plates shall be 316 Stainless Steel minimum unless otherwise specified and mounted between flange tap type orifices flanges complete with jack screws. Each plate shall have a tab which projects beyond flanges. The word UPSTREAM bore diameter, line size and pressure rating shall be permanently marked on upstream side. The tag number and plate material shall be permanently marked on downstream side. Based on the project material selection guide, materials like Inconel 625 shall be considered for sour service.

Orifice plate design and dimensions shall conform to the recommendations of ISO 5167 (PART 1, 2, 3 & 4). For orifice plates mounted in horizontal pipe runs, weep holes shall be provided in steam and gas flow installations where there is possible condensation or in liquid flow to allow vapour to escape. Weep holes shall only be supplied if specified on requisition data sheets.

Orifice meter run upstream and downstream straight run requirements shall be according to the recommendations of ISO 5167 (PART 1, 2, 3 & 4).

The upstream face of the orifice plate should be as flat as can be obtained commercially. Surface roughness shall not exceed the criteria set in ISO 5167 (PART 1, 2, 3 & 4).

For orifice plates installed in RTJ orifice flanges, orifice plate holders may be used. For sizes up to 3” the holder may be fabricated integral with the plate. For sizes above 3”, the orifice plate shall be separate and removable from the holder. In this case, a universal type orifice plate, one without a tab, shall be used. Holder shall be of the same material as the orifice plate.

Orifice plate thickness will be according to the recommendations of ASME-MFC-3M: Measurement of fluid flow in pipes using Orifice, Nozzle and Venturi.

Orifice plate shall be used for line sizes 2 inch to 24 inch. The minimum flange rating shall be 300# class.

Limitations of orifice plates include their susceptibility to damage by foreign material entrained in the fluid and to erosion.

Design of orifice plate installations shall conform to ISO 5167-1 and ISO 5167-2 or API MPMS 14.3.1 and API MPMS 14.3.2 (equivalent to AGA 3), as specified by project.

DP for orifice sizing shall limit the maximum DP to 500 mbar.

If the design DP exceeds 500 mbar, the proposed maximum DP shall be approved by Company.

To eliminate expansion factor problems for gas and steam service, static pressure of a compressible fluid shall be at least 30 times greater than the DP. For example, if the static pressure is 300 kPa (43 psi) the DP shall be less than 10 kPa (40 in H2O).

Material for orifice plates shall be designed for the fluid handled. Preferred material is Type 316 austenitic stainless steel. Other materials, including those to satisfy requirements for sour service as detailed in ISO 15156 (NACE MR 0175), may be specified in conformance to service requirements.

Drain holes shall only be used if the pipe exceeds DN 100 (NPS 4) and agreed by Company.

Diameter of drain hole shall not be greater than 0.1 times diameter of orifice bore.

Drain hole orientation shall be in conformance to Table 8.3.

Table 8.3 – Drain Hole Locations

Condition	Location and use of drain hole
If condensation is likely to accumulate in the pipes. (1)	Through bottom of orifice plate, to avoid accumulation of liquid
If entrained gas bubbles are likely in a liquid stream or gas development (because of pressure loss in the liquid stream).	Through top to permit gas to pass to downstream side of orifice plate.
Notes: 1. Accumulation of condensate at the base of orifice plates used in wet gas measurement can affect the discharge coefficient. Appropriate corrections shall be made in plate discharge coefficient calculations.	

For wet gases with liquids not near their boiling point, the orifice plate shall be installed in a vertical plane with flow downwards.

If the orifice plate is installed horizontally, a drain hole shall be specified in the bottom of the plate.

Orifice plates shall be mounted in one of the following locations:

a. Between orifice flanges.

b. In a single chamber orifice fitting (sometimes called “junior”) that allows retraction, removal, and replacement of the orifice plate.

If the gas composition is not stable, a vibrating spool type density meter installed either directly in a pocket downstream of the flow device or as a relative density meter, may be required to meet the performance specification of the flow device.

If ring tight joints (RTJ) flanges are used for a Class 2 system and the orifice plate needs to be removed routinely for inspection an orifice carrier or fitting shall be provided.

Use of flange taps on RTJ flanges shall be subject to agreement by Company.

Tapping arrangement for orifice plates in line sizes DN 50 (NPS 2) and above shall be flange taps.

Tapping arrangement for orifice plates in line sizes below DN 50 (NPS 2) shall be corner taps.

The orifice plate Beta ratio shall be between 0.20 and 0.60 for liquids and between 0.20 and 0.70 for gases and steam. Beta ratio of 0.75 is acceptable for orifice plates in 24 inches and larger pipelines.

Minimum bore diameter for orifice plate shall be 6 mm.

Orifice plate thickness shall be between 0.005D and 0.02D.

ISA standard sharp-edged, concentric orifice plates shall be used in all installations that indicate, record, and transmit process flow measurements unless process condition require otherwise. If unrecoverable pressure loss or other constraints preclude their use, another measuring device shall be selected.

Measuring elements shall be designed as recommended by ISO 5167-1 to 4 and 5168 standards.

Orifice plates shall be ANSI 316 stainless steel unless otherwise specified and mounted between flange tap type orifice flanges complete with jack screw.

Each plate shall have tab which projects beyond flanges.

The word UPSTREAM, bore diameter, tag. No., line size and pressure rating will be permanently marked on upstream side. The item number and plate material will be permanently marked on downstream side.

8.5.2.2 Orifice Calculations

The ratio of the orifice diameter to inside pipe diameter or beta ratio shall be between 0.40 and 0.75. If required by process conditions and with COMPANY approval, ratios down to 0.10 (according to ISO 5167(PART 1, 2, 3 & 4 limits) can be used.

The differential pressure ranges generally run from 2.5kPa to 50kPa (10 in. WC20°C to 200 in. WC20°C), regardless of the meter size. 25 Kpa is preferred, calculated per ISO 5167 PART 1, 2, 3 & 4. Calculations shall be made for flange tap.

8.5.3 Straightening Vanes / Flow Conditioners

Use of straightening vanes or flow conditioners shall be subject to COMPANY approval. Flow Conditioners or Straightening Vanes shall be selected in accordance with ISO-5167 / API MPMS 14.3.2.

8.5.4 Meter Runs

Meter runs for flow measurements made for material balance, custody balance and accounting will be shop fabricated from specially selected pipe to conform to ISO 5167 PART 1, 2, 3 & 4. The length of the prefabricated meter run plus the straight field piping shall conform to ISO 5167 PART 1, 2, 3 & 4.

Meter runs for the measurements used in normal control functions, local indication, and/or recording on minor process streams shall be field fabricated using standard mill run pipe but will be smooth and free from blisters and scale. The piping configuration will conform to ISO 5167 PART 1, 2, 3 & 4.

For normal measurements, Pipe shall be as a minimum as per pipe class and for custody measurement it shall have special pipe with material specifications as per pipe class but additional finishing/coating internally as required etc.

Class 2 metering runs shall conform to column "A" for "zero additional uncertainty" requirements based on Beta and process piping arrangement described in ISO 5167-1 or equivalent based on API MPMS 14.3.1, as specified by project.

Class 3 metering runs may conform to column "B" for "0.5% additional uncertainty" limits based on Beta and process piping arrangement described in ISO 5167-1 or equivalent based on API MPMS 14.3.1, as specified by project. Use of shorter lengths shall be subject to approval by Company. ISO 5167-1 has 2 minimum straight runs listed. One is for “zero additional uncertainty”; the other is for” 0.5% additional uncertainty”. The minimum required lengths for the 0.5% uncertainty case are roughly half that of the zero case.

For lower rates of flow, the following may be specified:

a. Small bore special purpose meter runs.

b. Differential pressure transmitters with an integral orifice.

Except for wet gas or steam flows, metering runs shall be arranged horizontally.

For wet gas, preferred orientation is upward flow for liquids near their boiling point.

8.5.5 Venturi Tubes, Low Loss Tubes and Flow Nozzles

Venturi tubes, low loss tubes, and flow nozzles shall be used where high-pressure recovery is necessary or where only low inlet pressure is available.

Venturi tubes shall be preferred to measure suction flow of centrifugal compressors.

Venturi tubes and flow nozzles of circular cross section shall be constructed in accordance with the requirements of ISO 5167 PART 1, 2, 3 & 4, unless otherwise specified, only one pressure tapping shall be provided for upstream and one for downstream pressure measurement.

Tap connections shall be ¾” Socket weld.

Alternatives to orifice plate may be used if a differential pressure device is preferred but there are other factors which could make an orifice plate unsuitable:

a. Permanent pressure loss.

b. Available straight length.

c. Process fluid e.g. solid content.

d. Large line sizes.

Venturis and flow nozzles shall be designed in conformance to:

a. ISO 5167-3 or ASME MFC-3M-2004 for flow nozzles and venturi nozzles, as specified by project.

b. ISO 5167-4 or ASME MFC-3M-2004 for venturi tubes, as specified by project.

c. ISO 5167-5 for V-Cone, as specified by project.

Other flow devices shall be designed to recognised industry standards and shall be agreed by Company.

For cone type devices, in applications where stress on the cone is of concern, an additional supporting strut shall be specified if warranted.

An independent flow calibration on a fluid similar to the product being measured in order to determine the V-cone meter discharge coefficient shall be considered. Larger V-cone meters (DN 300 [NPS 12] and above) are typically fabricated with a hollow central cone. This construction may not withstand high pressure transients in operation. The option of a solid centre cone may be required with attendant implications relating to cost, weight and element design.

The V-Cone Flow Meter is an advanced differential pressure instrument. Due to the built-in flow conditioning design, the V-Cone is more useful in tight-fit and retrofit installations in which the long runs of straight pipe required by Orifice Plates, Venturi Tubes, and other technologies are either impractical or unavailable. Use of V-Cone meters shall be subject to COMPANY approval.

8.5.6 Restriction Orifice Plates

Restriction orifice plates are devices for creating a certain pressure drop or for limiting a flow rate.

The construction of Restriction Orifices shall be in accordance with the recommendations of ISO 5167 PART 1, 2, 3 & 4, Orifice plate material shall be based on the project material selection guide considering sour, non-sour service. Minimum orifice Plate thickness shall be in accordance with ASME-MFC-3M, Table 3

Bore size calculation shall be in compliance with ISO-5167, ANSI/API MPMS Ch. 14.3.1/AGA Report No. 3, Part 1.

Minimum bore diameter for restriction orifice plate shall be 3 mm.

Aerodynamic noise calculations shall be in compliance with IEC 60534-8.

For temperature above 450° C or for materials other than 316 Stainless Steel the relevant dimensions shall be adapted to suit the application.

For restriction orifices installed in RTJ flanges, orifice plate holders may be used. For sizes up to 3” the holder may be fabricated integral with the plate. For sizes above 3”, the orifice plate shall be separate and removable from the holder. In this case, a universal type orifice plate, one without a tab, shall be used. Holder shall be of the same material as the orifice plate.

The specification of restriction orifice plates shall take into account:

a. The nominal size (normally equal to line size)

b. The rating.

c. The material.

d. The orifice diameter resulting from calculations using sizing equations in ISO 5167 PART 1, 2, 3 & 4. The dimension shall be the calculated dimension rounded off to the nearest 0.1 mm.

e. The need of bleed holes shall only be specified for orifice plates in horizontal piping of 2” or larger.

f. The thickness which is selected to withstand the full differential pressure per recommendations of ASME: Fluid Meters.

For sizing the orifice for restriction orifice plates the sizing equations in ASME-MFC-3M shall be used.

Multi-Stage orifice plates shall be used for large pressure loss applications (typically, more than 20.0 bar per stage). Restriction orifice assembly shall be of welded construction with plate martial suitable to withstand severe service conditions. Bore sizing calculations along with aerodynamic noise calculations shall be subjected to COMPANY’s approval.

Orifice assembly gaskets shall be supplied (by others) suitable for process fluid and piping classes.

8.5.7 Coriolis Meters

Coriolis meter systems shall be designed in conformance to API MPMS 5.6.

Coriolis meter installations shall have rigid mountings upstream and downstream that are isolated from plant vibrations.

For Coriolis meter applications the meter housing (the means of providing environment protection) may not be considered as secondary containment, depending on the manufacturer. Therefore, a means of eliminating the hazards associated with sensor tube failure shall be incorporated in conformance to safety, tube failure section of API MPMS 5.6, as follows:

a. Where Coriolis type meters are to be used for hazardous or toxic liquid measurement, safety precautions shall be taken to limit hazard due to tube rupture:

   i. By totalling enclosing the tubes within a pressure vessel of rating for the service.

   ii. By automatic isolation of the meter by upstream and downstream valves.

   iii. With a bursting disc or other form of protection.

b. Risk analysis may also be required. The vibrating tube of Coriolis meters is relatively thin when compared to line pipe thickness. Very careful attention needs to be given to material compatibility with process fluid.

Imposed pipe stress across meter flanges shall be eliminated by pipe work design, such as by keeping pipe stress off the flanges of Coriolis meters. Varying pipe stress across meter can cause significant shifts in meter zero and span calibration with some models.

Coriolis meters shall be installed so that solids do not accumulate in the vibrating tubes.

For dual tube Coriolis meter types, the installation orientation shall be selected to promote even, homogeneous flow distribution through both tubes. The orientation of dual tube type Coriolis meters is to be selected so as to minimise out of balance effects due to different gas void fractions in the two sensor tubes arising from any unavoidable presence of gas phase in liquid applications.

Unless recommended by Supplier, Coriolis meters for liquid service shall be mounted as follows:

a. Upstream of automated isolation valves so that if flow is stopped, fluid remains under pressure. This reduces any chance of bubbles entering the meter.

b. In horizontal runs, with the tubes down.

c. In vertical pipes, in the “flag” position with liquid flowing upward through the tubes. On some models, tubes may be mounted in a flat plane.

Coriolis meters for gas service shall be mounted as follows:

a. In horizontal runs, with the tubes up.

b. In vertical pipes, in the “flag” position with gas flowing upward through the tubes. On some models, tubes may be mounted in a flat plane.

Coriolis meters for slurry service shall be mounted as follows:

a. In horizontal runs, with the tubes up for self-draining.

b. In vertical pipes, in the “flag” position with gas flowing upward through the tubes. On some models, tubes may be mounted in a flat plane, but the installation will not be self-draining.

When mass flow measurements are required in the processing of fuels and other chemicals, mass flowmeters may be used. These types of flowmeters provide increased accuracy (0.25 % of reading) and reliability and fast, dynamic responses which make them fully suitable for continuous industrial operation.

Meter sizing calculations shall be submitted by the VENDOR. The flow meter shall operate within their linear range and with the design flow at no more than 70%-meter capacity. The mass flow measurement shall be unaffected by changes in temperature, pressure, flow profile, viscosity and small volumes of air or gas in the flowing stream. The flow meter shall have flanged connections. The flow meter shall be rated for the design pressure and temperature per the line class.

The transmitters shall be integrally mounted where the metering tube is accessible or remotely where the metering tube is inaccessible. The transmitters shall be of a ‘Smart’ type modular microprocessor-based design. The calibration parameters shall be stored in non-volatile memory and be capable of being reconfigured in the field.

The selected location for Coriolis type flow meters must be free of sources of electromagnetic interference and vibration. The inlet and outlet piping must be anchored securely to avoid transmitting stresses and vibration to the flow meter. The sensing tubes must be mounted such that slug flow is minimized and entrained gases can exit the meter. In addition, the piping must remain full during operation. Adequate backpressure must be maintained to avoid flashing and cavitation.

The flow meter shall be rated for the design pressure and temperature as per the line class. The flow meter sensor shall have a 316L housing as a minimum, unless the line class requires otherwise. Sensor housing shall be provided with required safety arrangements to withstand the line pressure, in case of a leak in the sensor tube. In addition, fault alarm shall be provided in this case. The sensor shall comprise of flow tubes which are vibrated at their natural frequency by an electromagnetic drive system and shall incorporate electromagnetic sensors located on each side of the flow tube assembly to measure the phase shift resulting from a twist in the flow sensor tubes, which is directly proportional to the mass flow. The natural frequency is a function of density and shall also be measured.

Refer ASME MFC-11 for the selection, installation, calibration, and operation of Coriolis flowmeters for the determination of mass flow, density, volume flow, and other parameters.

Meter sizing shall consider the maximum allowable fluid velocities within the meter body and allowable pressure drop (as per process design), while maintaining the specified accuracy at minimum specified flow ranges.

8.5.8 Thermal Mass Flow Meter

Thermal Mass Flow Meter is based on a principle of thermal dispersion. The rate of heat absorbed by a flow stream is directly proportional to its mass flow. It is a low-cost alternate for flow measurements in large size ducts (like combustion air). Use of thermal mass flow meters shall be subject to COMPANY approval.

This type of meter can only be used with fluid have significant amount of specific thermal conductivity and having homogeneous/uniform component. The straight run requirements shall be as per ASME MFC-21.2-2010.

It is not recommended for wet steam measurement or other fluids with entrained liquids.

8.5.9 Turbine Meters

If particulate carryover can occur, a mesh strainer shall be installed 15 pipe diameters upstream of the turbine meter.

Design of turbine meter installations shall conform to API MPMS 5.3 - Measurement of Liquid Hydrocarbons by Turbine Flow Meters.

Mesh size shall be selected to ensure that entrained particulates do not exceed the clearance between turbine blades and the wall of the meter. Supplier recommendation shall be followed for selection of mesh.

The minimum back pressure requirement on turbine meter shall not be less than:

$2\Delta p + 1.25pv$

Where:

Δp = Pressure drop across meter.

Pv = Absolute vapour pressure of fluid at maximum meter operating temperature.

8.5.10 Magnetic Flow Meters

Magnetic flow meters shall be installed so that the meter tube runs liquid full and there is no entrainment of gas or vapour.

If installed in a vertical line, flow shall be upward to ensure meter is liquid full.

Temperature limitations that apply to non-metallic liners shall be considered.

Earthing requirements defined by manufacturer shall be followed.

Continuous electrical contact to the same earth potential shall be made for the liquid, the piping and the meter.

Magnetic flowmeters may be used for potable water and may be considered for very corrosive applications and for applications involving measurement of abrasive and/or erosive slurries.

These flowmeters may be considered where no restrictions in the flow stream are allowed. If the liquid conductivity is equal to 20 microS/cm or greater, most conventional magnetic flowmeters can be used. Special systems are also available which will measure the flow of liquids with threshold conductivities as low as 0.1 microS/cm. For measurement of fluid velocities below 1m/s the instrument shall be of the DC field type.

Two wire 24 V DC type flow meter is preferable. Earthing ring / terminal of suitable material to be provided. Since this technology relies on electromagnetic fields, earthing the meter tube is essential for safety as well as for meter operation.

Magnetic flowmeter sizing calculations shall be subjected to COMPANY's approval.

8.5.11 Ultrasonic Flow Meters

Time of flight ultrasonic meters installed in line shall be the preferred type. Doppler is not recommended, and use is subject to Company approval.

Cross correlation type are applicable only where other types of meter are unsuitable (for example, 2-phase flow).

Installation of meter shall conform to the following:

a. ISO 17089-1 for gas service, if application is for allocation metering.
b. API MPMS CH5.8 or ISO 12242 for liquid service.

Ultrasonic meters shall have fully developed symmetric turbulent flow.

Lines shall run full of fluid.

Ultrasonic meters shall be placed upstream of flow or pressure control valves.

Ultrasonic time of flight meters shall not be used for liquid service where the presence of free dispersed gas exceeds 0.5% by volume at line conditions or where water in oil exceeds 5% by volume at line conditions.

Ultrasonic meters shall not be located within 3 m (10 ft) of pumps or compressors, in addition to straight length requirements.

Installation of ultrasonic meters is critical, particularly alignment of the probes and accurate measurement of inter-probe distances. The manufacturer's recommendations shall be followed.

The liners used shall be designed for the application, bearing in mind reactions that might occur with trace fluids and temperature limitations that apply.

Ultrasonic flow meters of the leading-edge (transit time) type may be considered where no restrictions in the flow stream are allowed or a rangeability of more than 3:1 is required.

Digital multi-path type ultrasonic gas flowmeters may be considered in gas services or applications that require high accuracy or mass balance. These meters offer no-line obstruction or pressure loss. They require minimum maintenance and are ideal for:

a. Transmission systems and take-off stations
b. Compressor stations for efficient operation and compressor surge control
c. Plant Information Management
d. Flare measurements (this is mandatory)

Number of paths (planes) shall be decided based on the accuracy requirements. Meter sizing calculations shall be submitted by the VENDOR. Meters with size lower than line size can be considered subject to meeting the flow capacity, pressure drop and velocity requirements. The flow measurement shall be unaffected by changes in viscosity and distorted flow profiles shall have negligible effect. The flow meters shall operate within their linear range and with the design flow at no more than 70% of meter capacity.

Meter sizing shall consider the maximum allowable fluid velocities within the meter body and allowable pressure drop (as per process design), while maintaining the specified accuracy at minimum specified flow ranges. Acceptable maximum velocity in the metering skid is limited to a maximum of 25 m/s.

The flowmeter sensor shall be of retractable type and shall be provided with retractable tools to remove and replace the sensor, with the pipe under pressure.

The flow meter shall have flanged connections and rated for the design pressure and temperature as per the line class. The transmitters shall be of a 'Smart' type, modular microprocessor-based design. The calibration parameters shall be stored in non-volatile memory and be capable of being reconfigured in the field.

The selected location for flow meters must be free of sources of electromagnetic interference and vibration. The inlet and outlet piping must be anchored securely to avoid transmitting stresses and vibration to the flow meter. In liquid services, the pipe sizing shall ensure that pipe must remain full during operation with adequate backpressure maintained to avoid flashing and cavitation.

For measurements with high turndown ratio (typically for flare applications), multiple output corresponding to different ranges shall be provided. Ultrasonic flow meters used for flare applications shall have minimum 2 paths. The transducer design shall allow on-line removal.

Ultrasonic flow meters shall cover the entire range. In fuel Gas and Flare applications, the meters shall be configured for multiple ranges to match with the field indications. Ultrasonic flow meters shall be provided with the required spool pieces for calibration.

Ultrasonic flowmeter sizing calculations shall be subjected to COMPANY's approval.

The manufacturer should be consulted if any of the following are expected:

a. when highly attenuating gases, such as carbon dioxide and hydrogen, can be present;

b. when the operational conditions are near the critical point of the gas mixture;

c. when non-hydrocarbon gases can be present, and the sound velocity is being used to determine the molecular weight;

d. when the total sulphur level, from materials such as mercaptans (thiols), hydrogen sulphide, and elemental sulphur, exceeds 320 μmol/mol;

e. when there is the possibility of a liquid carry-over from separators or scrubbers;

f. Salt deposits.

Doppler clamp-on type ultrasonic meters conforming to BS 8452 are simple and cheap to install but only function on fluids with some particle or gas/air entrainment. Clamp-on types are only appropriate for installations unable to accept inline, or for a temporary measurement.

Use of clamp on type instrument requires COMPANY approval.

8.5.12 Positive Displacement Flow Meters

Positive displacement flow meters shall be sized so that maximum expected flow rate is approximately 75% to 90% of the flow meter's rated maximum flow rate.

Number of accessories shall be limited so that torque required for their operation is less than 80% of rated torque generated by the flow meter.

Upstream strainer shall be used, with size of strainer mesh 400 μm (40 mesh), 6 mm (¼ in) maximum. Suppler recommendation shall be followed.

The meter shall have an upstream filter, sized to supplier's recommendation, maximum 100 μm (140 mesh).

Displacement meters may be used for batch operations, or high accuracy totalizing. A removable strainer with air eliminator shall be installed ahead of each meter.

Positive displacement meters shall have flanged connections and the body material shall be minimum carbon steel unless the application requires other material, e.g. stainless steel.

Positive displacement meters are not recommended for use with non-lubricating liquids such as propane, butane, etc., and when applied for such liquids they shall be provided with automatic pressure lubrication of bearings, gears, etc.

Flow limiting devices shall be considered to prevent over-ranging of positive displacement meters.

Certain types of positive displacement meters have their maximum capacity limited not only by flow, but also by the maximum allowable pressure drop across the meter. Consideration shall be given to limiting the maximum pressure drop especially when the meter is used with liquids having a high viscosity.

Meters shall be protected against damage due to hydraulic shock, caused for example by quick opening or closing of a valve.

Positive displacement meter systems shall be in accordance with API MPMS Chapter 5.2.

The positive displacement meters shall have the following features:

a. Double case.

b. No mechanical contact of the rotor parts inside the metering chamber.

Design shall include quick and easy replacement of meter internals.

8.5.13 Weirs

Weirs shall provide a head in excess of 0.25 kPa (1 in H_20) at operating rates of flow.

a. For small rates of flow, a triangular or V-notch type of weir is preferred.

b. If large quantities are to be measured in limited space with minimum loss of head, a rectangular or trapezoidal weir is preferred.

Approach channel may be made shorter if baffle plates are placed across it near the inlet end.

8.5.14 Miscellaneous Flow Meters

If paddle type flow switches are installed in pulsating flow streams, they shall be located at least 10 pipe diameters downstream of the source of pulsations and in a straight run of pipe.

Variable area meters shall be Stainless Steel tube with magnetic follower type on hydrocarbon service unless otherwise agreed by COMPANY.

Glass or plastic tube variable area meters shall be maximum DN 15 (NPS ½) and rated for at least twice the MAWP.

Glass tube meters shall only be used:

a. On non-hazardous service.

b. In analyser sampling systems.

c. To meter purge gas or water flow rates, or non-dangerous fluids.

Metal tube variable area meters with magnetic followers shall be used for hydrocarbon service.

Thermal flow meters may be complete self-contained flow controllers with integral control valves. Refer to API RP 551, Section 2 for additional information.

Vortex meters shall be sized such that maximum expected flow rate is approximately 75% to 90% of flow meter rated maximum flow rate.

8.5.15 Flare Gas Metering

Flare gas meters shall be designed for the following:

a. "Normal" operating range. Specifically: minimum flow indication (e.g. purge rates); base loading (e.g. normal operating rates to flare); and average excursions (e.g. flows expected for planned maintenance operations).

b. "Maximum" flow indication. Lower accuracy may be acceptable in some situations such as predictable dumps to flare (e.g. temporary loss of gas recovery).

c. Flare "design maximum" flow. This usually far exceeds sensible maximum flow indication requirements. Meters do not need to be sized to accurately measure occasional emergency flows or inventory blow downs. However, the meter needs to be robust enough to withstand the design maximum flow.

d. The practical turn-down required.

8.6 Wireless Instrumentation

During the design of the installation, precautions shall be taken regarding the number of devices and strength of the network, taking into account plant density (vessels, equipment and obstructions).

When selecting update rate, frequency vs. acceptable battery life shall be established using supplier documentation to establish the update rate to battery life relationship. Excessively high update rates will cause the battery to discharge quickly and require maintenance activities to replace the battery.

Preference shall be given to suppliers who provide wireless instruments that communicate using industry standard protocols IEC 62734 (ISA-SP 100.11a) or IEC 62591 (Wireless HART).

Proposals to use wireless shall be agreed by COMPANY prior to implementation. Typically wireless instruments may be used for Criticality Level 3 & 4 equipment where approved by COMPANY.

Site surveys (location of gateway and instrumentation) to create 2D/3D models, propagation tests and identify sources of interference are necessary steps in the design. Interface with the current automation systems and existing available capacity can prove to be an issue. Instruments that have high power consumption such as Coriolis meters often need additional power supplies and hence are not entirely wireless. Process information and diagnostics from an existing instrument can be sometimes be obtained by installing an auxiliary device which allows access via wireless.

8.7 Solar Powered Instruments

SUPPLIER shall not provide any solar powered instrumentation or equipment unless approved by COMPANY.

Solar Power systems providing power to an installation are normally provided by Electrical.

If COMPANY approval has been granted for the use of solar powered monitoring and control instrumentation equipment, then the SUPPLIER shall include this technology within the package equipment design. Design shall include maintenance of the system.

8.8 Multi Variable Instrumentation

Proposal to use multi-variable devices shall be agreed by COMPANY prior to implementation. Instrumentation able to measure more than one variable is available and continues to develop. For certain applications it may offer benefits, for example mass flow metering where one device may offer differential pressure, pressure and temperature measurements. A single failure can affect all measurements. Avoid unless a significant benefit can be demonstrated.

8.9 Other Instruments

8.9.1 Density

Vibrating element type density instruments may be installed either in a bypass loop or, with small pipes, with the flow routed directly through.

Provision shall be made to maintain the densitometer in the event of failure without disrupting the overall flow measurement.

8.10 Speed Instruments

Speed-measuring instruments are usually supplied as part of rotating equipment. For further details see Specification AGES-SP-04-007 Instrumentation for Packaged Equipment Specification.

On large rotating equipment, the speed measurement shall have a separate channel in the machine monitoring system.

For equipment such as forced draught fans of boilers and furnaces, where the speed instruments are supplied as part of the equipment, their make and type shall be as approved by COMPANY.

9 ANALYSERS

This section is intended to be used as a guide and other analysers can be selected based upon the application and project requirements.

Continuous Emissions Monitoring is covered elsewhere.

9.1 Gas Chromatographs

9.1.1 General

Gas chromatograph Supplier shall provide a chromatograph system consisting of the following items, as specified on data sheets:

a. Automated stream selection manifold.

b. Chromatograph analysers for installation within a shelter or house.

c. Chromatograph controllers for installation within a shelter, house, control room or equipment room.

d. Equipment for network communications between the devices in the system, for installation in an equipment room.

Chromatograph analyser and its controller shall be designed for wall or floor mounting, as defined on data sheets.

9.1.2 Automated Stream Selection Manifold

P&ID shall provide and detail any sample stream select manifold system required.

Manifold and chromatograph shall be provided as an assembled and pressure tested system.

9.1.3 Analyser

Sample injection shall be inhibited until after the chromatograph oven reaches operating temperature.

Ovens shall have independent temperature controls to provide a stable operating temperature for the analytical columns and detection to assure reproducible component analysis.

Ovens shall be protected against overheating due to instrument air failure or malfunction.

Detector output signals shall be shielded against common mode noise and normal mode noise in addition to RFI and EMC.

Detectors shall be provided with protection to prevent element damage due to loss of carrier gas.

Automatic igniter and hydrogen shutoff shall be incorporated in flame type detectors to protect against flame failure.

Catalytic air clean-up unit shall be provided in the air supply of flame ionisation detectors.

Flame photometric detectors shall use zero grade air.

Carrier gas shall be hydrogen, nitrogen, or helium if hydrogen or nitrogen cannot be used.

For each carrier gas the following shall be included, if specified on data sheets:

a. Gas cylinder manifold with two stage pressure regulation.
b. Inlet and outlet pressure gauges.
c. Low pressure valving.
d. Gas cylinder pressure regulators shall be equipped with a relief facility.
e. Regulators shall be equipped with 316 Stainless Steel diaphragms, as a minimum.

Flow rate of the carrier gas shall be adjustable without shutting the system down.

Analysers shall be equipped with electronic pressure control.

Analyser specifications to conform to or exceeded are:

Repeatability shall conform to Table 9.1,

Table 9.2 or

Table 9.3. Repeatability in this case is defined as a percentage of full scale of each measured peak using the same sample on the same analyser and with 100% confidence during the time of the agreed factory acceptance test (usually 24 hours).

Table 9.1 – Thermal Conductivity Detector

Component range	Analyser repeatability
2% to 100%	±0.5%
0.2% to 2%	±1.0%
0% to 0.2%	±2.0%

Table 9.2 – Flame Ionisation Detector

Component range	Analyser repeatability
2% to 100%	±0.5%
0.05% to 2%	±1.0%
20 ppm to 500 ppm	±2.0%
1 ppm to 20 ppm	±3.0%

Table 9.3 – Flame Photometric Detector

Component range	Analyser repeatability
All	±3.0%

Sensitivity shall be ±0.5% of span. This shall not be interchangeable with the lower level limit of detection as specified on data sheets.

Cycle time shall be as specified on data sheets.

"Column" life shall be a minimum of six months during normal operation.

Flame type detectors shall have flame arrestors in the vent and a local flame ignition switch. Flame arrestor shall be accessible for maintenance purposes.

Intercolumn detectors shall be provided on gas chromatographs to allow for set-up of heart cut and backflush timing.

Oven power may be separated from the analyser processor power.

9.1.4 Controller

Analyser controller shall be microprocessor based, with one controller dedicated to each analyser.

Electronic components shall be:

a. Designed for installation in a non-air conditioned, non-heated shelter.
b. Protected against trace H_2S and humidity.

Manual operation of the analyser shall be available at both the analyser and the maintenance workstation.

Loss of power to the controller shall not cause loss of controller memory.

Detector reading shall be automatically zeroed prior to each measurement cycle.

Peaks to be measured shall be separated from all interferences so that a few seconds of baseline are provided on either side. Skimming and dropping tangents shall not be used to establish peak area.

9.1.5 Supervisory workstation

Chromatograph workstation will be located in an analyser room, control room or equipment room.

Workstation shall, as a minimum, have the following:

a. Access to the analysers on the network.
b. Able to start and stop chromatographs on the network.
c. Simultaneous acquisition of real-time chromatographs from up to ten analysers without degrading network communication speed.
d. Intuitive menu driven interface to analysers.
e. Monitor and modify chromatograph control parameters, for example:
    i. Oven and other heating zone temperatures.
    ii. Electronic pressure regulator settings.
    iii. Stream selection valves.
    iv. Column valve times.
    v. Peak integration periods.
    vi. Other analyser operating tables.

Changes downloaded to analysers at the end of the analysis cycle in which changes were made.

Overlay of stored and real-time chromatograms.

Long term, selective chromatogram storage.

Peak table modification occurring directly from peak changes made to a chromatogram. Peak names transferable to the table in a similar manner.

Perform mathematical calculations on raw data and output results to other analysers and the ICSS.

Monitor and acknowledge analyser status and all hardware and software alarms.

Enable and disenable reporting of data to any output device.

Data to be readily transferable to and from each analyser.

Generate analyser maintenance reports and performance service factors.

Initiate auto validation and calibration of analysers and transmit data to the ICSS.

Auto-validation, to be initiated on a timed basis, and manually from the analyser and from the ICSS system including a signal to the ICSS to display when the analyser is in validation mode.

Perform statistical trending of analyser variables and measured compositional data.

Analyser parameters and process data to be readily transferable to commercially available software programs such as MS Excel.

External connections to other LANs and PCN.

Analyser operating and maintenance manuals and spare parts list either resident in the workstation or available for loading into the workstation from a disc.

Data link to the ICSS to remain operational in the event of workstation failure.

9.2 Moisture

9.2.1 Measurement Principle

Moisture analysers shall be relative humidity measurements. Sensors shall be “thin film” polymer capacitance measuring devices or tuneable diode laser absorption spectroscopy based.

Other technologies may be proposed subject to approval by Company.

9.2.2 Analyser Requirements

Capacitance moisture analysers shall be inline devices.

Tuneable diode laser absorption spectroscopy devices shall include a sample probe unit, complete with sample isolation valve, designed for direct line mounting.

Moisture analyser shall provide a stand-alone field mounted packaged system.

9.2.3 Performance Requirements

Supplier shall advise what the maximum response times are for both detection of moisture and drying out time after detecting moisture.

9.3 Dewpoint

Hydrocarbon dewpoint analysers shall use chilled mirror technology.

Analyser shall differentiate between hydrocarbon and water dewpoint based on surface tension.

Operation shall be fully automated with a programmable cycle time.

Analysers shall be complete with a sample probe and sample system including filtration.

9.4 Hydrogen Sulphide

H_2S analysers shall use one of the following methods for on-line measurement of H_2S gas:

a. Lead acetate.

b. Ultraviolet.

c. Gas chromatography.

d. Tuneable diode laser.

H_2S analysis, if based on a lead acetate tape method, the tape shall be advanced only when saturated.

H_2S analysis, if based on a lead acetate tape method, a fault pre-alarm signal and contact shall alert when tape needs replacement within the next week of operation.

Other technologies may be proposed subject to approval by COMPANY.

Concentrations of Hydrogen Sulphide - H_2S gas shall be measured and displayed with 0-50 ppm range.

H_2S detectors shall have the following characteristics:

a. Semi-conductor / solid state type for the desert plants. The selected sensor shall be free from ‘sleep’ effect and shall not require frequent calibration (no more than once in a year).

b. Electro-chemical type shall be used, especially for the installations where the atmosphere is wet and humid.

c. Shall provide a 4-20 mA output.

9.5 SO_2 Detectors

Concentrations of Sulphur Dioxide - SO_2 gas shall be measured and displayed with 0-20 ppm range.

SO_2 detectors shall have the following characteristics:

a. Be solid state/ electrochemical cell type with electrodes.

b. Shall provide a 4-20mA output.

9.6 Total Sulphur

Total sulphur analysis shall use either gas chromatography or mass spectrometer method for on-line measurement of total sulphur in gas.

Operation shall be automated with a programmable cycle time.

Analyser shall include a facility for automatic calibration at configurable intervals.

Response time of the analyser shall be less than 60 seconds.

9.7 Oxygen

9.7.1 General

Oxygen in gas analysers should be inline devices. An analyser with a sample conditioning system may be considered if it offers significant benefits over an inline device, subject to Company approval.

Oxygen analysers shall be either paramagnetic or zirconium oxide.

9.7.2 Paramagnetic oxygen

Paramagnetic oxygen analysers shall be supplied with a sample conditioning system to provide a dry, non-condensing sample.

In dirty services, as defined on data sheets, an automatic sample flush filter system shall be provided.

Sensors shall be current indicator type.

Dumbbell type sensor may be proposed for clean services.

9.7.3 Zirconium oxide oxygen

Supplier shall propose either a heated or non-heated probe based on the process temperature. Heated probes work from ambient temperatures, non-heated probes depend on process conditions to raise temperature above 550°C (1020°F) so cannot give a reading during start-up but can be more robust.

Gas composition will be specified on data sheets.

Automatic purge and calibration gas capability shall be provided.

Standard probes for use up to 700°C (1290°F) shall be 316L stainless steel.

9.8 Hydrocarbon in Nitrogen

Hydrocarbon in nitrogen analysers shall provide a continuous measurement of hydrocarbon content in gas using a flame ionisation detector principle or tuneable diode laser absorption spectroscopy.

Analysers shall be supplied as a complete system to handle sample flow at process conditions specified on data sheets.

9.9 Analyser General Requirements

Turbidity analysers shall be mounted inline.

Analysers shall be able to be isolated and removed for maintenance without the need to shut down the process. Should the Suppliers proposed solution require a shutdown of the process in order to remove the analyser or the associated sensor then the Supplier shall highlight this within their quotation.

All analysers shall be micro-processor based and single stream.

All analysers shall be designed for field use; laboratory type equipment shall not be used.

Analysers where the detector is immersed in the process stream are preferred to analysers that require a dedicated sample system.

Inline analysers shall be designed to be removed without the need to shut down the process.

Self-diagnostic routines and calibration functions shall be provided as standard. The Supplier shall supply details of the available self-diagnostic routines and calibration functions and the required calibration intervals and any specialist equipment required.

Routine maintenance, calibration, zeroing, filter changes, or adjustment to sample flow rate, temperature and pressure shall not be required more frequently than every seven days.

The analyser measurement range shall be as specified on the data sheet with the operating point at approximately mid span. The analyser accuracy shall be defined on the instrument data sheet.

Analysers requiring field equipment (hardware) alterations to effect range changes are not acceptable.

The analyser shall be designed to achieve the minimum analysis time lag without complicating the analysis and impacting on the analyser availability and/or maintainability.

For each analyser, the Supplier shall specify overall time lag that shall include any process lags and sample analysis delay that may exist within the analyser.

The analyser measured variable output shall generally be 4-20mA, isolated, 2-wire, linear over the specified range and certified for IS use.

Each analyser shall have as a minimum an ‘out of service’ alarm generated whenever the analyser or sample system is not functioning in a manner consistent with correct analysis of the process stream.

This shall be in the form of a changeover volt-free contact, either gold plated or noble metal, rated 24V DC 500mA and suitable for use within an IS circuit.

Typical fault detections generating “out of service” are as follows:

a. Sample flow failure;
b. Power failure;
c. Calibration sample selected;
d. Analyser in maintenance mode (manual switch);
e. Analyser self-diagnostic giving “fatal fault”;
f. Analyser purge failure.

Each analyser shall have local interrogation and indication facilities. The interrogation facilities shall be accessible without the need for removing analyser cover, etc. To assist with maintenance, analysers that require field adjustment shall have a local display facility visible from the adjustment point.

The Supplier shall ensure that if an unsafe condition occurs, the analyser shall, if required, “trip” to a safe state and an appropriate alarm generated.

Where measuring elements are mounted in the main process line, it should be possible to remove it without interrupting the process or creating a hazardous condition.

9.10 Materials

The Supplier shall specify all materials used in the construction of the analyser. Aluminium and copper shall not be used.

All components exposed to or in direct contact with the medium subject to analysis shall be suitable for the pressure and temperature and be resistant to corrosion from that medium.

As a minimum all wetted metal parts shall be 316L Stainless Steel. Other materials such as Hastelloy, Inconel or Monel shall be used where required, with particular attention paid to materials in contact with seawater.

In addition, all wetted parts shall not:

a. React with the sample;

b. Allow entrance of contaminants via osmosis or diffusion;

c. Leach material to the sample;

d. Cause fire hazards or unsafe conditions.

PTFE paste shall not be used unless approved by Company. Any O-ring material shall be of suitable material for the nature of the sample construction and finish shall be to the guidelines described in IEC 61831.

Positive Material Identification (PMI) shall be performed.

9.11 Performance Requirements

For analysers in environmental applications the performance of the analyser shall fully comply with the environmental requirements.

For the rest of the analysers measurement uncertainty shall be equal or better than ±4% of the measured value and repeatability shall be equal or better than ±2.5% of analyser range.

The response time of the analyser shall be less than 30 seconds.

The measurement uncertainty of the selected equipment / technology shall prevent the deterioration of measurement by interference of solids (suspended or otherwise).

9.12 Water in Oil

Water in Oil analyser will be required to measure the water in oil fraction in the test separator oil stream outlet for the period of the well test. This will be needed to determine the total water production and the mean water in oil fraction for the test period. There are effectively two options, online water cut measurement and offline sample analysis.

Using an online water cut meter would provide a continuous measure of water fraction that could be used with the oil stream flow meter output to calculate the flow weighted mean water in oil fraction for the well test period. That mean could be used to calculate total water for the well test.

Offline analysis of water fraction (ref Section 6.2.4) would be performed in the facility laboratory. This would require the availability of a mixer and a Karl Fischer titration unit.

It is the Supplier's responsibility to select the best technology for the application and ensure compliance with the relevant sections of this specification.

The sample could be collected automatically using a grab sampler or manually at an appropriate frequency during the well test period. Note that the sample collection method could impact on the uncertainty of the results.

All analysers shall be micro-processor based and single stream.

All analysers shall be designed for field use; laboratory type equipment shall not be used.

Due to the nature of the technology water in oil analysers shall be inline devices, it is not envisaged that a sample system will be required. Supplier shall inform Company if they feel a sample system is required to meet the performance requirements of the application.

It shall be possible to isolate and remove all analysers without loss of integrity, hazard to personnel or without the need to shut down the process.

Self-diagnostic routines and calibration functions shall be provided as standard. The Supplier shall supply details of the available self-diagnostic routines and calibration functions and the required calibration intervals and any specialist equipment required.

Routine maintenance, calibration, zeroing, filter changes, or adjustment to sample flow rate, temperature and pressure shall not be required more frequently than every seven days.

The analyser measurement range shall be as specified on the data sheet with the operating point at approximately mid span.

Analysers requiring field equipment (hardware) alterations to effect range changes are not acceptable.

The analyser shall be designed to achieve the minimum analysis time lag without complicating the analysis and impacting on the analyser availability and/or maintainability.

For each analyser, the Supplier shall specify overall time lag that shall include any process lags and sample analysis delay that may exist within the analyser.

The analyser measured variable output shall generally be 4-20mA, isolated, 2-wire, linear over the specified range and certified for IS use.

Each analyser shall have as a minimum an 'out of service' alarm generated whenever the analyser or sample system is not functioning in a manner consistent with correct analysis of the process stream.

This shall be in the form of a changeover volt-free contact, either gold plated or noble metal, rated 24V DC 500mA and suitable for use within an IS circuit.

Typical fault detections generating "out of service" are as follows:

a. Sample flow failure;
b. Power failure;
c. Calibration sample selected;
d. Analyser in maintenance mode (manual switch);
e. Analyser self-diagnostic giving "fatal fault";
f. Analyser purge failure.

Each analyser shall have local interrogation and indication facilities. The interrogation facilities shall be accessible without the need for removing analyser cover, etc. To assist with maintenance, analysers that require field adjustment shall have a local display facility visible from the adjustment point.

The Supplier shall ensure that if an unsafe condition occurs, the analyser shall, if required, "trip" to a safe state and an appropriate alarm generated.

Where measuring elements are mounted in the main process line, it should be possible to remove it without interrupting the process or creating a hazardous condition.

9.13 Oil in Water

Dual gamma ray absorption, ultrasonic, capacitance or conductivity devices shall be considered to detect oil in water. Supplier shall detail best technical solution within their tender.

Light scatter or other methods that can be affected by turbidity, sediment or other non-hydrocarbon particles in the fluid shall not be used.

Oil in water analysers shall be inline devices, the measuring element package shall include a sample probe unit for line mounting, complete with sample isolation valve(s), suitable for direct line mounting.

Sample probes shall have as a minimum connection a 1½" 300# ANSI flange; sample probe material shall be 316L Stainless Steel.

A close coupled field mounted transmitter shall be supplied to transmit the reading back to the microprocessor-based electronics unit in the Local Equipment Room (LER).

Transmitter output shall be 4-20mA.

The microprocessor-based electronics unit for the analyser shall be supplied suitable for panel mounting (19" rack mount) within a control cubicle, which will be located in an environmentally controlled equipment room.

Facilities on the electronics unit shall include a local display and shall enable calibration of the system such that the output can represent the following water content measurements:

a. Parts per million by volume (ppmv);

b. Parts per million by weight (ppmw);

c. kg water/106 Sm^3 gas.

The analysis system shall provide the following outputs to the Company's control and monitoring system for display in the central control room:

a. RS 485 / RS 422 / Ethernet;

b. Contact output(s) for common fault or trip alarm(s).

Analyser accuracy shall be equal or better than ±4% of the measured value and repeatability shall be equal or better than ±2.5% of analyser range.

The response time of the analyser shall be less than 30 seconds.

Oil in water analysers shall be inline devices, the measuring element package shall include a sample probe unit for line mounting, complete with sample isolation valve, suitable for direct line mounting.

Oil in Water analysers shall be based on either Infrared absorption or Ultraviolet fluorescence technologies.

The oil in water analysis facility is required to provide a fully stand-alone field mounted packaged system.

The analysis system shall provide the following outputs to the Company's Integrated Control and Safety System (ICSS).

a. 4 – 20 mA signal representing 0 – 50 ppmv oil in water;

b. Alarm contact outputs for separate high oil content;

c. Contact output(s) for common fault or trip alarm.

9.14 Installation

Where analysers are required to be mounted in local free standing enclosures, the enclosure shall be three-sided as a minimum and constructed of 316L Stainless Steel and shall be so designed and constructed to allow free ventilation such that equipment contained within them can be certified the same as the area classification. The enclosures shall be designed in order to minimise heat gain through solar radiation.

If it is necessary, due to the specified climatic conditions to fully enclose the analyser, the Supplier shall propose a suitable design, taking due regard of the need for forced ventilation etc.

The enclosure shall be provided with its own lighting and local switch certified for use in the hazardous area in which it is located.

The Supplier shall supply isolating switch(es), for all analyser power supplies, certified for the hazardous area in which they are located.

The analyser enclosure materials of construction shall be fire resisting and resistant to attack from oil and chemicals. All fittings, supporting framework, cable trays etc, shall be compatible with the house construction to minimise corrosion.

The Supplier shall ensure that when the enclosure is used for equipment support, there shall be sufficient rigidity to minimise vibration. Where necessary, anti-vibration mountings and flexible pipe connections should be used to isolate vibration sensitive equipment from pipework or structural vibration.

Where size and weight necessitate, lifting of each analyser enclosure shall be by Supplier specified “eye-bolts”, mounted on each analyser enclosure roof, at suitable locations, sized to take the load of analyser enclosure fully fitted with equipment.

Should specialised equipment such as “spreader bars” be required, they shall be supplied by the Supplier. The Supplier shall provide detailed “Mechanical Handling Procedures” where applicable.

The Supplier shall provide outline General Arrangement Drawings of the proposed enclosures within his quotation, including mounting details and weight. The Supplier shall also provide details of any analyser elevation requirements in relation to the sample point and return point elevations. Design and layout shall consider accessibility and maintenance of components. Removal of the component shall not require removal of other installed components.

9.15 Sample Systems

9.15.1 General

The requirements in this section are applicable if the offered solution requires a sample to be brought to the analyser via an insertion probe and transportation system, which may need conditioning before presentation to the analyser inlet.

For each analyser (as applicable) the Supplier shall provide, as a minimum, the following data for the analyser sample (each parameter shall be quoted as minimum, normal and maximum):

a. Flowrate

b. Inlet Temperature

c. Outlet Temperature

d. Inlet Pressure

e. Outlet Pressure

Note: The flow rate of flammable fluids to the analyser shall be limited by an excess flow valve.

The overall sampling system shall include all equipment necessary to provide the analyser with a continuous sample representative of the process stream in respect of the property to be measured and within conditions specified for the analyser. The sample point shall be located in a turbulent area within the main pipeline to ensure that the analyser receives a representative sample stream.

The Supplier shall supply a recommended procedure for sample transportation and conditioning. This shall include drawings depicting the sampling system from point/probe (including sample probe design) to analyser and all associated connections.

Quantities and types of components shall be shown including any pumps and/or compressors that may be required to achieve correct analyser inlet conditions and reduce sample transport lags. The sample system shall also make provision for a test sample to be taken close to the analyser inlet without "starving" the analyser.

The Supplier shall provide details regarding any requirements for heating, cooling or trace heating of the sample, from sample point/probe to the analyser. Insulation and/or tracing of sample lines will only be applied where absolutely necessary.

The drawings/documentation shall include minimum sample temperature requirements from probe/sample assembly to the analyser inlet. Any "break point" for the application of heating or cooling including insulation requirements shall be shown.

The number of joints and compression fittings in sample line shall be kept to a minimum.

The sample transportation and conditioning system shall have facilities for flushing, venting and or draining complete with vent and drain valve(s).

For remote mounted analysers the Supplier shall indicate the expected sample lag, using their transportation and conditioning system, for each analyser, for tubing lengths of 20m, 50m and 100m. The calculations for these lags shall be supplied and be broken down into transport and conditioning system times.

The sample conditions and approximate sample composition shall be as stated on the analyser data sheets. The data sheets will also indicate the potential process conditions under an upset scenario.

Analysers and sample systems shall be protected from damage in the event of any item of equipment failure.

9.15.2 Sample Probe

The Supplier shall include sample probes and shall provide details within their quotation.

The sample probe orientation and tag number shall be clearly stamped on the flange and be visible in its final installed position. The sample probe flange shall be 1½" 300# minimum. The insertion length (measured from inside wall of pipe) shall be a minimum of 30mm and a maximum of ½ diameter of pipe bore + 10mm, taking due regard of the flowing velocity within the process line.

To minimise measurement lag, the contained volume of the probe shall be as small as practicable.

If in-line probes are used a means of withdrawing the probe under pressure shall be considered, to allow for cleaning, maintenance or replacement without shutting down the line.

Materials of construction shall be compatible with the process medium but as a minimum, 316L Stainless Steel shall be used. Inconel 625 shall be selected for seawater services.

9.15.3 Transportation System

Transportation system tubing material will be compatible with that used for the sample probe and conditioning system (as applicable).

9.15.4 Conditioning System

The sample conditioning system shall supply a representative sample at the required analyser inlet conditions with the minimum of time lag, which shall be 1 minute maximum.

If it is not possible for the time lag to be ≤1-minute, Supplier shall seek the Company's approval of conditioning system prior to implementation.

It shall be equipped with pressure relief facilities as necessary in order to prevent damage to the analyser under process upset conditions.

If the outlets are taken to a closed or common system, double block and bleed lockable isolation valves shall also be provided on the outlet by the Supplier in order that maintenance can be performed on individual installations.

The materials and components used for the sample system shall be suitable for the process medium but as a minimum, 316L Stainless Steel shall be used. Higher grade alloys shall be selected for seawater services.

A local pressure and temperature (if required) gauge shall be provided at the outlet of the sample conditioner.

The Supplier shall provide facilities for calibration and/or laboratory checks.

9.15.5 Sample Return/Disposal

Samples from analyser outlets shall be returned to the slops/effluent system if it is not possible to return them to the process.

When sample coolers are used, both the inlet & outlet of coolant shall have isolation valves. Coolant inlet line have necessary instrumentation to monitor coolant pressure and temperature.

9.15.6 Tubing and Fittings

Instrument tubing shall be supplied in accordance with the requirements in appendix A1.

Seawater services shall be alloy tubing, typically Inconel 625, with double ferrule type fittings manufactured from a compatible material.

Selected material class shall be dependent upon the piping material class of the installation.

All tube fittings shall be compression fittings; twin-ferrule type to Metric dimensions, all fittings shall standardise across the project.

10 FIRE AND GAS DEVICES

10.1 General

AGES-PH-03-002 Fire and Gas Detection shall be used in the selection of the detection and deluge system for the application. This section expands on that and Section 20.17 covers the applications and typical interfaces for the F&G system.

The purpose of fire detection is to detect fires as early as practical to minimise immediate consequences and prevent escalation.

All F&G detectors and alarms shall be connected individually to the plant main F&G system where all the F&G detection logic and associated cause & effect shall be implemented. Exceptions to this are:

a. Gas Turbine Compressors, which have standalone F&G detection systems.

b. Non process buildings such as maintenance building, warehouses, administration building, accommodation building which have their own fire detection panels with common alarm reporting to Fire Station and /or MCR (as applicable). Fire Detection panel may be addressable system or part of plant F&G system.

Fire & Gas detectors shall be RFI /EMI protection in compliance with IEC 61000.

All gas detectors shall be line monitored for any open/short circuit and earth faults. Detector installed above false ceilings in floor voids, ducts shall have remote status indication to avoid removal of access panels, etc.

Where detectors have no direct access, such as the air intake duct, all flammable and toxic gas detectors shall be provided with a remote calibration connection facility for ease of calibration.

Wherever detector voting is provided without fail safe design for trip / executive action, any detector fault and non-availability shall be considered in the logic to meet the design intent. In such cases, the detector fault and non-availability shall automatically degrade the voting logic to prevent any mal operation.

Gas detectors provided in the HVAC air intake duct shall be installed in adequate straight length section, to ensure homogenous sampling. Further the number and type of sensor selection shall consider the fast response requirement, considering the air velocity in the duct and the complete duct area coverage. Smoke detectors may also be installed in recirculation loops to detect smoke in rooms an shut off recirculation.

Fire & Gas System shall be implemented as part of the ICSS based on fault tolerant architecture. Fault tolerance is of primary importance; in particular the system shall be able to continuously operate without any plant operation disturbances when cards are being replaced.

Safety Integrity Level (SIL) of the Fire & Gas detection function shall be set in the LOPA and SIL evaluation for respective executive functions.

10.2 Fire and Gas Alarm colour code in graphic displays

The following colour code shall be used:

Flammable Gas Alarm Level 1: Blue

Flammable Gas Alarm Level 2: Blue

Gas Detector, Toxic Gas Alarm Level 1: Yellow

Gas Detector, Toxic Gas Alarm Level 2: Yellow

Fire Alarms (Smoke Detectors, Flame Detectors, Heat Detectors, Fusible Plugs etc): Red

Manual Alarm Call: Red

Deluge Valve Opened: Red

Security Gate Opened: Red

Refer to AGES-PH-03-002 Appendix B for details of colours.

10.3 Alarm acknowledgement

Alarm condition shall automatically display the correct area and detector symbol, for the area where the alarm has occurred. Alarms shall be individually acknowledged from the expanded display or from the alarm display, where the flashing symbol identifier will go steady and continue to stay in alarm until the alarm condition is no longer present and reset.

Fire & Gas alarm details

10.3.1 Fire Alarm Call Point:

The manual call point will be indicated with a circular border. The display properties are as follows:

Normal: Circular border in red with centre dot in grey.

Alarm: Circular border in red with centre dot in red.

10.3.2 Hydrocarbon/Flammable Gas Detector:

The flammable gas detector will be indicated with a square border. The display properties are as follows:

Normal: Square border in blue with centre dot in grey.

High Alarm: Square border in red with centre dot in blue.

Hi Hi Alarm: Two square borders in red with centre dot in blue.

10.3.3 Toxic Gas Detector:

The toxic gas detector will be indicated with a triangular border. The display properties are as follows:

Normal: Triangular border in yellow with centre dot in grey.

Alarm: Triangular border in red with centre dot in yellow.

10.3.4 Fire Detectors (Smoke Detector, Flame Detectors, Heat Detectors, Fusible Plugs etc)

The fire detector will be indicated with a slanted square border. The display properties are as follows:

Normal: Slanted Square border in red with centre dot in grey.

Alarm: Slanted square border in red with centre dot in red.

10.3.5 Deluge Valves:

The deluge valve indication should indicate the area of coverage. It should differentiate whether it covers specific equipment or a group of equipment. In case of deluge valve activation, the area covered by the deluge valve shall also turn to alarm state. The deluge valve indication will be as follows:

Normal: Green colour with line also in green.

Test: Cyan colour with green discharge line.

Discrepancy: Magenta colour with green discharge line.

Valve opened: Red colour.

The valve object will be flashing in the event of alarm and will be steady on acknowledgement

10.3.6 Extinguishing Systems:

The Inergen extinguishing system will be indicated as follows:

Manual Mode: Grey

Auto Mode: Green

Activation/Discharge: Orange blinking and steady on acknowledgement

Inhibited: Amber

Manual Release: Red

Manual Abort: Red

10.3.7 Wind Indication:

The direction measurement shall be superimposed with the north indication and the direction measurement will be preferably in 15 deg. Units as a minimum.

HVAC Inlet Damper Status

Normal: Grey

Operated: Red

Maintenance Override Switches (MOS) related to FGS

Normal: Grey

Operated: Green

Security Gate Switch Related to Pipelines

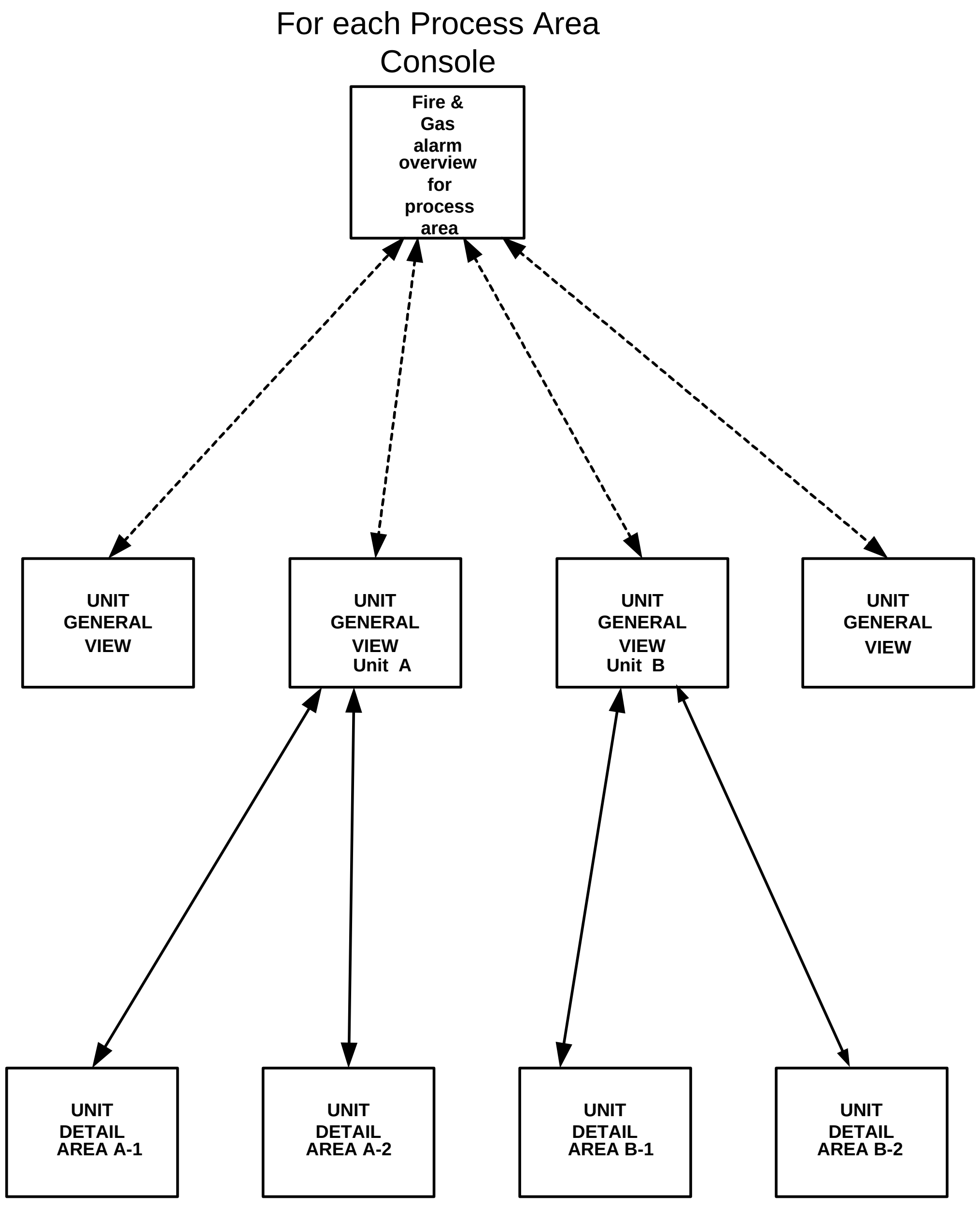
Normal (Close): Green

Opened: Red

Notes:

1. In case of ‘Smart’ gas detector status information like calibration status, detector fault, dirty optics shall be shown in the relevant graphic pages.
2. Detectors in calibration mode to be indicated in Cyan.
3. Fault/removed detectors to be indicated in white for Process plants and Magenta for Pipeline SMC system.
4. Inhibited devices to be shown in Amber.

F&G Display Hierarchy



10.4 Beacon

Visual alarms, consisting of a flashing beacon, shall be installed to give warning of fire or gas release; in general plant areas, this will be the function of the Public Address / General Alarm (PAGA) system driven by suitable outputs from the FGS.

For specific areas, additional localised beacons may also be required, as defined on the C&E Charts, and these shall be directly driven from the FGS.

The housing material shall be 316L stainless steel, environmental protection to IP66.

The beacons shall be located so that they will be visible in the area for which they are to provide a warning and are accessible for maintenance.

The beacon shall have a flashing frequency of 60 flashes per minute. The effective luminous intensity shall be 300 candela (cd) minimum. Lamp shall be Xenon - discharge type. The dome for flash tube on the flashing beacons shall be made up of transparent toughened glass. A lens guard / cage shall also be provided for all the beacons.

10.5 Sounders

Detection of a fire or a gas leak / release shall be announced by audible means in the plant area and within buildings (control rooms, substations etc.) this will be the function of the PAGA system, driven by suitable outputs from the FGS.

For specific areas (usually enclosed or noisy), additional localised sounders may also be required, as defined on the C&E Charts, and these shall be directly driven from the FGS.

The outside audible alarms shall produce a sound pressure level of up to 115 dBA (27 tones, user selectable) with the frequency of 1000 Hz at a radius of one meter.

Inside audible alarms shall be 6 W for small enclosures or 10 W for large enclosures and shall have the same tone selections as those provided for the outside alarm to allow co-ordination between all audible alarms in a particular fire-zone. Up to 6 distinct alarm tones may be programmed within the PAGA system, some of which will have to be rebroadcast by the FGS, including:

Prepare to Abandon Platform (or FPSO facility) Alarm;

Gas Alarm;

Fire Alarm; and

General Alarm.

Audible alarms shall be of the horn type. The audible alarms in buildings may be silenced after acknowledgement of the alarms, by the operator at the control room HMI / Critical Alarm Panel (CAP) only. No local silencing of audible alarms shall be permitted. Where beacons and sounders are supplied as a combined unit, the beacon and the sounder shall be driven via separate outputs from the FGS to allow the audible alarm to be turned off whilst the visual alarm remains on.

10.6 Deluge Valves

Each automatic on-off valve / deluge valve used for fire protection shall have a three-position switch (open/automatic/closed).

Valve status (i.e. open / close) is to be monitored in Fire station. Remote activation facility shall be provided in the fire station and the plant Fire and Gas System.

10.7 Addressable Detector System

Addressable fire detection systems are to be deployed in internal areas that are classified as "non-hazardous" in terms of their contents, and where specific location information is required to direct the response. The LQ are a prime example of where addressable systems are used, in that they do not contain a process hazard, are protected from external hazards by their HVAC Systems, and contain a number of individual rooms / cabins.

Addressable fire detection systems shall be operationally fully integrated into the main FGS, which will provide the main interfaces to the PAGA system and the HMI and mimic panels.

Within the majority of the areas that are to be monitored by the addressable fire detection systems, there are no hydrocarbon gas or fuel hazards to fuel flaming fires. The main source of hazard is expected to be over-heating electrical equipment therefore the earliest method hazard detection would be by detection of the smoke produced internally, before it erupts into flames, therefore infra-red flame detection is not deployed as standard. The fire detection system shall therefore generally comprise of addressable smoke and heat detectors plus addressable MACs. There shall be a minimum of two loops for each area that is protected via an addressable system of detectors, with adjacent detectors connected to different loops. Each zone as defined by HSE shall have dedicated addressable loops.

Detection of a fire or an abnormal event within the areas that are covered by addressable systems shall be announced via the function of the PAGA system, as defined in the Communication Study, driven by suitable outputs from the addressable system controller and / or the FGS.

Addressable system components shall be manufactured from or fire-resistant zero-halogen materials as they are likely to be used in areas that form part of the temporary refuge. Only if these are not available shall flame-retardant zero-halogen materials be used. Fire prevention and mitigation shall be of the highest levels throughout the LQ.

Addressable system components shall be designed and manufactured in accordance with the relevant sections of ISO 7240.

As the components of the addressable fire detection systems are to be deployed in internal areas that are classified as "non-hazardous", they may be de-rated in terms of their environmental protection ratings to IP42 for generally dry areas. However, for potentially areas "wet" areas, such as the galley / kitchens, communal showers / toilets and the laundry, an environmental protection rating of IP44 shall apply. For environmental protection ratings of devices located in external areas or those areas potentially subject to active fire protection and / or deluge, refer to Section 7.2.6 for details.

Automatic detectors shall be surface-mounted supplied with a mounting base and twist lock connector to facilitate flat-surface / ceiling-mounted detector installation. The designs of the mounting base and detector combination shall allow free entry into detection chamber through a 180° hemisphere. Ceiling-mounted detectors shall be self-resetting once the detected parameter has been cleared and conditions are back to normal.

10.7.1 Zone Controllers

Addressable loop controllers shall be capable of automatically triggering a fire alarm test; for the control rooms, offices and accommodation areas, this shall be synchronised for all zones and configured to be at the same time, to be held shortly before or after a scheduled shift-change when no-one should be sleeping.

10.7.2 Heat Detectors

Heat detectors of the electronic type (thermistors etc.) shall be used in preference to the rate compensated mechanical contact type used in the general process areas where aesthetics is the primary consideration (i.e. in accommodation areas).

The heat detectors shall react when the temperature sensor in the detector reaches the pre-set temperature setting. Heat detectors are usually deployed in locations where smoke can occur normally and thus smoke detectors will be prone to producing false alarms:

Galley and kitchen areas, due to cooking vapours;

Bathroom and shower areas, due to steam; and

Laundry and driers, due to steam.

10.7.3 Smoke Detectors

Optical detectors (Photoelectric) using light scattering to detect smoke particles shall be suitable for detecting smouldering type fires as well as flaming fires and are now deployed as the standard fire detector in most areas. Designs should feature an optical chamber with a light source that is reflected towards a light sensitive receiver. In the event of smoke entering the optical chamber, this will scatter the light or reflect it backwards, depending upon the style of sensor, and the detector will go into alarm. The design of the optical sensing chamber shall allow unrestricted smoke entry while minimising light entry from external sources.

Ionisation-type detectors were once generally deployed as part of the addressable loop system. However, as modern optical-based sensors have characteristics that are similar to ionisation smoke detectors, there is no longer any reason to use ionisation smoke detectors. Due the issues arising from their use of radioactive isotopes, this type of detector shall not be used.

For normally unattended areas of the plant, control equipment rooms, computer rooms, telecommunications equipment rooms, and similar that usually house their equipment in cabinets, special HSSD systems are typically deployed.

The detector shall include functions to detect and communicate any condition that might prevent smoke detection. Undetected failures in ability to respond shall be deployed in addition to installed detectors for the building.

For mounting in HVAC ducts, detectors shall incorporate a sampling tube system; sample tube connection to the detector shall be metric with a maximum of 10 sampling points.

Each detector shall have a Light Emitting Diode (LED) to indicate when the detector is in alarm.

10.7.4 Combination Multi-Sensor Detectors

Multi-sensors combine different types of detector into a single combination unit, with the usual combination being smoke and heat detection.

In some models, not only can the detector report the detection of high temperatures and smoke particles individually, they can also adjust the sensitivity of the optical sensor as the temperature changes, in order to enhance the sensitivity of the device to achieve the earliest possible detection of the fire.

Other models include infra-red flame detectors and Carbon Monoxide (CO) sensors in addition to smoke and heat detectors. The use of the infra-red sensor requires that there is a flaming fire, which should be unlikely within the environs of the LQ which, as it contains the temporary refuge, should be constructed to the highest standards in terms of reducing the risks of a spreading fire.

CO detection is often cited as an important means of detecting smouldering fires before they erupt into flames; however, the most common cause of CO poisoning appears to from a badly fitted and / or maintained heaters where combustion is incomplete and CO is inhaled over relatively long periods. The standards (and hence the detectors) appear to be designed around the prevention of this type of hazard, with its continuous production of low levels of CO, and thus their response times are allowed to run to more than 60 minutes.

10.7.5 Audio-Visual Alarms

Announcements and alarms regarding the detection of a hazard by the addressable system will be the function of the PAGA system, driven by suitable outputs from the FGS. It is expected that the PAGA system will adequately cover all areas that are protected by addressable systems, thus supplementary audio-visual warning devices are not required as part of the addressable systems.

10.7.6 Manual Call-Points

MACs shall generally be installed in locations that are easily accessible, along corridors, on landings at the entrances to escape routes and stairwells, and at emergency exits. MACs shall be located within 1.5 metres of each exit doorway on each floor.

Operation shall be via a pull lever, or protective-coated press to break / crack glass elements.

10.7.7 Door Holders and Switches

Within the environs of a building, there may be fire-doors which are in constant use (corridor partitions for example); to avoid these being permanently wedged-open, it may be more effective to allow them to be held-open by electro-magnetic interlocks, which can be released in the event of a fire. It is expected that these types of devices will consume too much power to allow them to be connected to the addressable loop, but the addressable loop controller(s) shall be capable of driving these, so that they may be released upon detection of a fire.

Where normally closed exits are intended for use only in emergencies, and they are secured by electro-magnetic devices rather than mechanically operated ‘panic’ bars, these locks shall be automatically released by the FGS when a fire or similar emergency condition is detected. Door release switches shall be fitted at each door to allow them to be opened in a localised emergency; these shall be similar to the MACs in style and operation, but in a different colour (usually green).

Opening any external emergency exit door shall raise an individual alarm via the addressable loop system, as this represents a potential breach of the clean-air pressurised protection provided by the HVAC.

10.8 Detection targets and positioning

All detection targets shall be based on area specific events.

Detection targets for both flame and gas detectors shall be set by consideration of detecting a fire or an accidental hazardous gas release or accumulation; before they are large enough to cause an escalating situation if not mitigated.

Detection targets shall be set for toxic or asphyxiant gas events based upon the concentration levels that can pose a threat to the safety of personnel working offshore.

Fire and gas mapping and / or gas dispersion modelling shall be used to determine and verify flame and gas detector positions in all external areas.

10.8.1 Fire Event Determination

For hydrocarbon and flammable liquid fires the detection target shall specify fire size (in terms of its radiated heat output, kW) and fuel type. The detection target for fire events shall have an area coverage (based on the flame surface area visibility).

Fire detection targets shall be based on the area specific results which provides modelled results for both jet fires and pool fires. Where there are no results for a particular location, the default flame detection target shall be used to assess, orientate and position flame detectors within the area.

Where there are additional hazards, such as adjacent hydrocarbon inventories, or items requiring specific protection, such as safety critical elements, additional detectors maybe deployed to provide enhanced coverage.

For non-hydrocarbon fires the detection target shall be based on a documented assessment of the hazard in each area.

10.8.2 Hazardous Release or Accumulation Event Determination

For flammable gas clouds the detection target is a pre-mixed cloud that, if ignited, could result in explosion overpressures or flash fires with an escalation threat. For hazardous accumulation events the detection target should specify gas cloud size and fuel type. If the flammable gas is also toxic or asphyxiant, more local detection may be required.

The gas detection target for hazardous accumulation events shall be based on a volumetric coverage.

Gas detection targets shall be based on the area specific results of the Flammable Hazards Analysis Report, which provides modelled results for both jet and pool fires plus unignited gas clouds. Where only the largest gas cloud data is available, the size of the smallest significant jet fire shall be used as the basis of the target size of the unignited gas cloud. If this results in a cloud that is larger than the default gas cloud in the table below, or if there are no results for a particular location, the default gas cloud detection target shall be used to assess, orientate and position gas detectors within the area.

Table 10.1 – Default Target Gas Cloud Sizes

Area Type	Gas Cloud Size
Offshore, enclosed area[1]	5 m LFL sphere[5]
Offshore, semi-enclosed area[2]	5 m LFL sphere[5]
Offshore, open area[3]	7 m LFL sphere[5]
Offshore, open deck area[4]	10 m LFL sphere[5]

Notes:

1. Fully walled area / package with forced ventilation or vents.
2. Typically, congested area with one or two open sides.
3. Typically, area with 2 open sides and grated floor or more than 2 open sides.
4. Typically, open deck areas without walls.
5. The idealised sphere generated from dispersion models. A release scenario is determined such that the Lower Flammable Limit (LFL) contour encompasses the same volume as the target sphere.

10.8.2.1 Acoustic Leak Detection

Acoustic leak detection provides the benefit of early hazard identification and may be installed in areas where the following requirements are met:

a. The fluid that could be released is in the gaseous or vapour phase;

b. The fluid has pressures of 15 barg or greater; and

c. The area is an open volume.

Leak detection targets shall be based on the area specific results of the Flammable Hazards Analysis Report, which provides modelled release rate results for jet fires. The release rate of the smallest significant jet fire shall be used as the basis of the targeted leak size. If this results in a release rate that is larger than the default detection target, or if there are no results for a particular location, the default detection target shall be used to assess, orientate and position gas detectors within the area.

10.8.2.2 Perimeter Detection

Perimeter detection may be used in place of volumetric detection for large open volumes if the following conditions are present:

a. The volume has no congested parts; and

b. The assessed hazard is migration of gas to other areas.

Deployment of perimeter detection shall respond to gas migration to other areas and towards major ignition sources.

Where toxic or asphyxiant gas detection by proxy is proposed, additional volumetric detection must be deployed to cover any areas where operators may be required to carry-out routine maintenance tasks, including their access pathways into and out of the equipment module.

10.8.2.3 Liquid Phase Releases

Low-level detectors (for heavy gas hazards) shall be installed in areas that contain inventories of process fluids, which if released to atmosphere, would remain in liquid state for a significant period.

Elevation of low-level gas detectors shall be specified based on their intended role and the nature of gases under consideration.

Low-level detectors should be initially arranged on 5 m spacing around the potential heavy gas release points, the locations shall be assessed and verified as part of the fire and gas mapping and gas dispersion modelling processes. Consideration shall be made to the dispersion of high-pressure releases and the potential location of an accumulated pool.

10.8.3 Toxic or Asphyxiant Event Determination

Safe working practices constitute the primary protection of personnel from toxic and asphyxiant gases.

When it has been determined that a fixed toxic or asphyxiant gas detection system is required a documented gas release risk assessment shall be carried out to determine the extent of the area(s) where personnel are deemed at risk, and to define an appropriate detection target that shall be achieved within the defined area(s). The detection target level defined shall be guided by the toxicity of the gas (or gases) concerned and shall be set at a level that ensures that personnel are not put at risk of harm to health. The detection targets shall be based on concentration and expressed in ppm by volume.

Where the allowable exposure levels are expressed in terms of average concentration levels per shift, the FGS shall maintain a rolling time-weighted average of the toxicity and / or asphyxiant gas concentration levels monitored by each detector and for each module / fire-zone area. The individual module / area data shall include both a time-weighted average based upon the maximum concentration level detected by any detector in that module and a time-weighted average based upon the average concentration levels from all of the detectors in the module. The FGS shall generate and output hourly time-weighted average data to the HMI, to enable the ICSS to produce-shift, daily and monthly reports for monitored toxicity levels.

The use of detectors shall not detract from the need for formal working practices to protect personnel from toxic and asphyxiant hazards.

10.8.3.1 Carbon Monoxide (CO)

Threat to personnel from machinery exhaust fumes inadvertently being leaked into an area should be eliminated where possible. If the threat cannot be eliminated or managed in another way fixed CO detectors should be installed in enclosed spaces and on ventilation intakes where personnel may be present.

10.8.3.2 Carbon Dioxide (CO_2)

If the threat to personnel is from machinery exhaust fumes, CO detectors should be used rather than CO_2 detectors, because CO is the primary toxin. If CO_2 may be a threat to personnel without CO being present, CO_2 or Oxygen (O_2) depletion detectors may be used. Detectors should be placed where personnel are present during normal operations such as designated entrances, exits, and walkways.

10.8.3.3 Nitrogen (N_2)

N_2 is not toxic, it is the main constituent in the air that we breathe (78% N_2, 21% O_2, 0.04% CO_2, and 0.96% Argon). The threat to personnel is, where pure N_2 it is used to for "inert-gas" purging in confined spaces, or enclosed areas, there is a risk that it will displace the O_2 and thus cause asphyxiation. As it is the lack of O_2 that is the critical factor, the monitoring for these spaces should not be for their N_2 content, it should be for the lack of a breathable atmosphere, and therefore, O_2 depletion detectors should be used in these locations.

10.8.3.4 Hydrogen Sulphide (H_2S)

H2S risk areas shall be classified according to the likelihood of H_2S being present in the atmosphere:

To provide a means of detecting H_2S with a lower maintenance method, for known H_2S concentrations in the production process of up to 500 ppmv, fixed flammable gas detection, using infrared technology, may be used to infer H_2S concentration if the hydrocarbon gases content volume in any release is at least 1000 times the H_2S content.

10.8.3.5 Narcotic Effects of Hydrocarbon Gases

The narcotic effect of a hydrocarbon mixture depends on the dose and the concentrations of the various hydrocarbons in the mixture. Enclosed areas with an inventory of hydrocarbon components of C_3+ should be considered narcotic risk areas in this regard. The minimum control measures are that confined space entry requirements shall apply to these areas.

10.8.3.6 HVAC Refrigerant Gases

Non-toxic refrigerant gas shall be used where possible. Within enclosed areas the potential for refrigerant leakage becoming an asphyxiant hazard shall be assessed.

Currently the various HVAC plant rooms containing the chillers has been identified as areas to be assessed. Where required, refrigerant gas detectors and associated area alarms shall be provided.

10.9 Detection Mapping

Detection mapping refers to a suite of techniques that use computer modelling to assess the coverage of detection systems against target hazardous scenarios. Detection mapping shall be used to design and/or assess optical and infra-red flame detectors and gas detector layouts whilst providing an auditable assessment trail of the detection system’s response to the specified detection targets. Detection Mapping is carried out by HSE.

Mapping is not required in general, non-hydrocarbon areas (such as living quarters and electrical rooms) where fire detector placement is based on a prescriptive rule set, in accordance with industry accepted codes and standards.

For each identified detection zone, a minimum of 2 detectors shall be installed.

Fire and Gas Mapping Studies shall include an overview of the mapping technique used, detailed results for each area/zone, detector types/models and optimised detector locations. Fire and Gas Mapping Studies require input from safety risk and operations throughout the process in order to develop a high-quality solution.

11 OUTPUT DEVICES

11.1 Control Valves

For application and specification of control valves, see AGES-SP-04-002 Control Valve Specification.

Control valves shall not be used for ESD functions.

For control valves used on anti surge applications that are also used as a recycling line, careful consideration shall be given to selection of the trim and characteristic of the valve to meet the process requirements.

11.2 Actuated Valves

For application and specification of actuated valves, see AGES-SP-04-005 Emergency Shutdown and On Off Valves Specification.

11.3 Actuator and Accessories

This section supplements the information contained in the following specifications which should be read in conjunction with this philosophy:

AGES-SP-04-002 Control Valve Specification.

AGES-SP-04-005 Emergency Shutdown and On Off Valves Specification.

11.3.1 Smart Valve Positioners

New control valves shall be selected with digital ‘Smart’ valve positioner.

Digital ‘Smart’ positioners with adjustable gain, auto tune, characterisation capabilities, and diagnostics combine the I/P function and the valve positioner function. They provide the ability to diagnose valve problems such as sticking, excessive lag, etc.

For ESD valves, positioners shall have capability to monitor valve movement, record demands and perform self-contained proof testing when required to allow accurate recording in compliance with functional safety requirements.

Pneumatic positioners shall have bypasses, except in the following cases:

a. If reverse acting positioners are required.

b. If split range positioners are required.

c. If actuator operating air pressure range is not suitable for control signal.

11.3.2 Booster Relays

Pressure and volume booster relays may be considered for control services under the following conditions:

a. Relatively fast system response to a change in valve position is desired.

b. Valves have controller pneumatic signal lines greater than 75 m (250 ft).

c. Valves have actuators with an effective diaphragm area greater than 0.13 m^2 (1.4 ft^2).

Booster relays shall be used for compressor anti-surge protection valves if stroke from full closed to full open is greater than 2 s.

If booster relays are required, the air supply line size shall be checked.

Relays shall have 316L body and internal parts.

Lockup relays may be used if process conditions demand that the control valve temporarily holds its last position in the event of supply failure (for example, to permit and orderly plant.

11.3.3 Solenoid Valves

Solenoid valves shall be 24 V DC.

Low power solenoids shall conform to the following:

a. Valves of a “friction free” design to ensure reliable operation at low power.

b. Voltage drop in wiring minimised.

c. Clean dry air supplied.

The solenoid shall be compatible with the switching capacity of the ICSS output card.

Universal form solenoids should be used.

Solenoid Valves shall have 316L body and internal parts.

Exhaust ports shall have bug screens and shall be self-draining.

The use of double acting actuators is subject to COMPANY approval. The solenoid valve shall dump only the appropriate side of the piston while maintaining full supply pressure to the other side of the piston.

Valves used for shutdown and emergency isolation duties shall conform to AGES-SP-04-005.

Trip solenoid valves initiated by a shutdown system to isolate and de-pressurise supply to control valve actuator shall be provided directly in the actuator supply line, downstream of any positioners, relays, or filter regulators.

Confirmation that port sizes and impulse tubing sizes are consistent with required actuator operating times shall be provided by valve supplier.

11.3.4 Handwheels

If local operation may be required, control valves shall be fitted with handwheels except in:

a. Emergency shutdown systems.
b. Handwheels may prevent a valve from travelling to its air/hydraulic supply failure position.
c. Control schemes for which local manual control is not feasible (for example, fast acting or highly interactive).

Handwheels shall not interfere with railings, conduit, or other equipment.

Valves on manifolds shall have seal or padlocking facilities provided.

11.4 Safety / Relief Valves

Conventional type relief valves shall be used where the back pressure is substantially constant e.g. atmospheric relief or high set pressures (total back pressure less than 10% of the set pressure). Conventional type relief valves shall be of the nozzle entry type having enclosed springs and conforming to API Standard 526, except for steam or hot condensate when open bonnets shall be used.

Devices shall be sized, selected and installed in conformance to API Standard 520,

Balanced type relief valves shall be used where back pressure conditions preclude the use of a conventional type (total back pressure exceeds 10% of set pressure). Bonnet and bellows vent shall be routed with minimum restriction. In bellows type pressure relief valves, bonnets shall be vented separately from discharge.

Pilot operated relief valves shall not be used in fouling or high temperature services. A pilot assisted pressure relief valve is preferred to a pilot operated valve. Pilot assisted valves shall be considered where high accuracy or rapid opening and closing are required.

Further information will be provided in the Corporate Specifications for Relief Valves.

11.5 Motor Operated Valve (MOV)

The actuators shall be intelligent type and shall be totally self-contained units, complete with mechanically and electronically interlocked reversing contactors, indicator lamps for power and manual operation, Integral control switches and LED indicators for open, closed and alarm. The actuator shall be supplied complete with motor, electrical control compartment, totally enclosed gear train and hand wheel.

The actuator shall have contactor starter, local/Stop/remote selector switch, control supply transformer and control modules. The actuator shall facilitate remote monitoring of valve position, valve alarms, actuator alarms, etc.

For large numbers of MOVs in an installation and where application permits, MOVs shall be interconnected with digital communication (e.g. RS485 or RS422) to provide valve status and diagnostic information at control room. For installations with few MOVs, hard wired or Foundation Fieldbus signals shall be used.

Limit switches shall be used for remote position indication. Magnetically operated proximity switches are preferred.

Refer to AGES-SP-04-005 Emergency Shutdown and On/Off Valves Specification for details on the MOV.

12 MACHINERY MONITORING

For monitoring the vibration and shaft position of large rotating equipment, the probes and oscillator/demodulators form part of instrument engineering but are usually supplied with the equipment. For main machines key phases shall be included. The make and type of these items shall therefore be agreed upon between instrument engineering and mechanical engineering at an early stage of the project. For further details see Specification AGES-SP-04-007 Instrumentation for Packaged Equipment Specification.

12.1 Temperature sensors

Temperature sensor shall be a 100 Ohm, platinum, three lead resistance temperature detector (RTD). Where possible, the sensor shall be a duplex type to provide a backup sensing element if the primary sensor fails.

12.2 Monitoring systems

12.2.1 General

Facility requirements for safety instrumented systems (SIS) as applicable to monitoring systems shall be obtained from COMPANY.

Note that the default is a 1 second delay on trip outputs (electronic overspeed detection is excepted). A second is enough time for modern systems to determine a faulty signal and avoid spurious trip.

12.2.2 Display

Digital displays shall be specified for shaft vibration, axial position channels, and temperature, with the display updated at a minimum rate of once every two seconds.

12.2.3 Power Supplies

Redundant power supplies shall be provided for the monitoring system fed as two separate feeds from a secure supply.

12.2.4 System-Output Relays

As a minimum, one pair of non-latching relays, alarm (alert) and shutdown (danger), shall be provided for each transducer signal monitoring:

De-energise to alarm and de-energise to trip shall be the standard.

12.2.5 Radial Shaft Vibration Monitoring

Unless otherwise specified, for monitoring radial shaft vibration, the full-scale range shall be from 0 to 250 micrometres (0 to 10 mils) true peak to peak displacement.

This scale range is likely to cover the majority of radial bearing clearances; but high-speed rotation with tighter bearing clearances might need a smaller full-scale range.

If an external system is used for the voting, then the logic in the monitor needs to be set to single.

It should be noted that, in a 2oo2 logic system, if one signal becomes faulty and does not violate the shutdown setpoint, then the trip protection will not work even if the other signal exceeds the shutdown setpoint. It is important, therefore, to set a high priority status to fault alarms.

Set point multiplication shall not be used.

12.2.6 Axial Position Monitoring

Unless otherwise specified the full-scale range for axial position monitoring shall be from –1.0 to +1.0 millimetres (-40 to +40 mils) axial movement.

The monitor indicated “zero” point shall be set to represent the rotor at the mid-point of its axial float within the thrust bearing.

12.2.7 Piston Rod Drop Monitoring

Proximity transducers shall be used to measure the drop of the piston rod during operation. Typically, a single probe is mounted in the vertical orientation to monitor piston rod drop, which is directly related to rider band wear.

As defined within API STD 670. an optional second horizontal probe per rod, and a once-per-revolution sensor may be installed to assist in condition-based diagnostics.

The vertical probe is typically mounted in the 6 o’clock position. Probes and cables are to be installed to prevent inadvertent contact with the piston rod and allow access through the distance piece cover for maintenance or adjustment.

Most horizontal reciprocating compressors rely on piston rider bands to support the piston and prevent contact with the cylinder liner. As these bands wear, the piston rod drops in the cylinder and moves in the rod packing in a corresponding amount. Typically, rider band wear is of an extended duration. Monitoring rod drop is a means of sensing the amount of rider band wear. In the event of full rider band depletion, there is a risk of the piston contacting the cylinder wall.

Two types of sensing devices are typically used for monitoring and the use of a trip in this instance is not usually recommended. The piston rod drop should be monitored, and the monitoring system fitted with an alarm if wear is becoming excessive.

Eutectic type devices provide a rudimentary level of detection. Importantly, this type of device has no advance indication of condition until the piston rod makes contact with the sensing device. SUPPLIER is advised that Eutectic type piston rod drop detection may be considered for noncritical applications only.

Non-contact type sensing provides an advanced level of detection and can aid in early detection of running gear problems. Rod position sensing may be expanded by implementing two probes, one in each of the vertical and horizontal directions.

12.2.8 Temperature Monitoring

The purchaser shall specify whether a shutdown function is required for temperature monitoring.

If a machine with hydrodynamic bearings is not protected by vibration monitoring and/or axial position monitoring, then a shutdown function should be specified for temperature monitoring.

12.2.9 Speed Indicating Tachometer

Tachometer shall be specified for variable speed drives.

The tachometer shall be digital, and its peak speed range shall cover all speeds up to 127% of rated speed of the driver.

12.2.10 Electronic Overspeed Detection

The range of the peak hold feature shall be at least 127% of the rated speed of the driver.

12.3 Transducer and Sensor Arrangements

12.3.1 Location and Orientation

12.3.1.1 Radial Shaft Vibration Probes

Deviation from standard probe arrangements shall be specified under the heading Probe Arrangement on the data sheet.

12.3.1.2 Axial Position Probes

Non-integral thrust collars that require hydraulic tooling to fit and remove from the shaft can be considered a good surface to monitor axial position. Loose thrust collars include those that are kept in position with lock nuts and tab washers.

A record shall be made of the set-up of the axial probes. This record shall include a schematic drawing showing the probes relative to the monitored surface; the probe voltages, monitor readings and dial indicator readings at each extreme of the rotor float within its thrust bearing.

12.4 Standard Tachometer Transducers

For steam turbine drivers it shall be possible to test the ability of the transducer to generate a speed signal once it has been installed in the machine. This shall be possible without the need to admit steam to the turbine.

This requirement is easily met if the turbine has a turning device capable of turning the rotor at a speed above the minimum threshold of the tachometer transducer. If the turbine does not have a turning device then consider designing, or ordering, a special test rig (e.g. a toothed wheel and a transducer mounting plate) that could test the transducers in the field immediately before their installation in the machine.

The steam turbine protection is at its most vulnerable when the start command has been given to the governor. At this point the tachometer transducer failure input has been overridden in order to allow the rotor speed to reach the minimum detectable by the transducer. Meantime the governor is opening the steam control valves.

If the transducers fail to send a signal to the governor, then the turbine could start to turn as more steam is admitted. The next trip signal would be from a time delay for the speed signal reaching the governor, but this might be set too long to prevent serious damage or even an overspeed. Testing the speed transducers' ability to generate a signal when installed would bring confidence in the governing and protection systems.

12.5 Electronic Overspeed Detection System Speed Sensors

For steam turbine drivers it shall be possible to test the ability of the transducer to generate a speed signal once it has been installed in the machine. This shall be possible without the need to admit steam to the turbine.

12.6 Mounting

If installation is at a remote, unpopulated location, armoured cabling shall be specified.

12.7 Inspection, Testing, And Preparation for Shipment

12.7.1 Mechanical Running Test

Specifying the contract monitoring system to be used during the mechanical run test of the machinery often draws an exception from the machinery vendor because of the disruption to their own test bed monitoring systems. This inevitably attracts an extra cost but might be worth considering if the machinery is to be supplied as a complete package with no fieldwork.

12.8 Alarm and Shutdown Settings for Vibration And Axial Position

12.8.1 General

Unless otherwise agreed the alarm and shutdown settings shall be as specified in Section 9 of API 670.

These criteria are not necessarily the same as the settings for alarm and shutdown points within the monitoring systems.

12.8.2 Shutdown Settings

12.8.2.1 Radial Bearings

The resultant value (S p-p) max) of the peak to peak displacement values measured in two orthogonal directions (SA and SB) is given by equation B.4 of paragraph B.3.2.1 of ISO 20816-1.

S p-p) max shall be the basis for the trip setting and should be the lesser of:

(a) 13200/ [(n)^0.5] microns {(520/[(n)^0.5] mils}, where n is the shaft speed in revolutions per minute or, (b) 95% of the diametral clearance of the bearing. As the voting logic for a radial trip is 2 out of 2 then the trip setting for orthogonal components SA and SB will be equal and is given by √ (S p-p) max/2).

12.8.2.2 Thrust Bearings

The shutdown set points for thrust bearings should be as described in figure 20 of API 670.

12.8.2.3 Anti-Friction Bearings

The shutdown set point for the monitoring of anti-friction bearings should be the Zone C/D value given in the appropriate table in ISO 10816-3.

12.9 Alarm Settings

12.9.1 Hydrodynamic Bearings

12.9.1.1 Radial Bearings

The logic for alarms is one out of two and each displacement measurement on an individual bearing shall have the same setting. The setting should be in accordance with the recommendation in paragraph A.4.1 of ISO 7919-3. The alarm setting shall not exceed the trip setting.

12.9.1.2 Thrust Bearings

The alarm set points for thrust bearings shall be as described in figure 20 of API 670.

12.9.2 Anti-Friction Bearings

The alarm set point for the monitoring of anti-friction bearings shall be the Zone B/C value given in the appropriate table in ISO 10816-3.

A physically and functionally independent rotating Machinery Protection system shall be provided. The system shall be state of the art and provide the means to accomplish the following:

Hardwired machine trip outputs to ESD System for machine protection.

Machine condition data to machine monitoring system to display data for reliability group.

All machines monitoring related data from the machine monitoring racks shall be available on ICSS. In addition, all relevant process data on the ICSS shall be transferred to the Machinery Monitoring System (MMS) for the purpose of Advanced Machinery Analysis by Reliability Engineers using advanced software.

13 INSTRUMENT INSTALLATION DESIGN

13.1 Tubing, Fittings and Valve Material Selection

Refer to appendix A1 for details on Tubing, Fittings and Valve Selection.

13.2 Instrument Air

The system shall be rated for all the connected loads plus a minimum of 20%.

The air supply to field mounted instruments and valve actuators shall be through individual isolating valves, filters and regulator sets with pressure gauges.

The piping group shall install a 2” NB (50mm NB) instrument air header with 1” NB ball valve branches for instrument air network. Where a number of instruments are grouped together then standardized instrument air manifolds (10way or 6 ways) shall be used for instrument air reticulation. These air manifolds shall be stainless steel with individual ball valves for feeders.

13.3 Instrument Air Supply

Instrument air shall be dry, clean (dust free) and oil free, and shall be provided by dry type compressors. Compressors should provide 7 barg minimum at the furthest consumption point from compressors.

Instruments shall use Instrument air at following conditions:

Normal pressure 7 barg

Minimum pressure 5.5 barg

Design pressure 10 barg

Water dew point -20°C at 7.5 barg

13.4 Instrumentation and Control Cabling

See AGES-SP-04-006 Instrument and Control Cables Specification.

Intrinsically Safe (IS) loop calculations shall be provided for all intrinsically safe circuits.

In order to ensure ICSS network availability and reliability, communication networks between the main control room and remote shelters/ IESs shall be segregated across different fibre optic cables. The fibre optic cable segregation shall be as follows:

a. Control (PCS) and Safety Networks (ESD, F&G, and BMS).

b. Sub systems*(MMS, Analyzers, MOV networks, etc.).

c. Information Systems, Telecommunications.

d. Electrical Systems, ECS, IPCS and PMS.

*Network for sub systems are mainly for the purpose of diagnostics, calibration, interface to ICSS, etc. and this shall not be combined with ICSS network.

IT infrastructure / network shall utilise the fibre optic cables designed for Process control (OT Network) network.

Fibre Optic cables shall have 100% spare fibres as a minimum. Communication cables shall be redundant and shall be diversely routed.

13.5 Cable Glands

Cable glands shall be designed and manufactured in conformance to EN 50262 and BS 6121 Part 1. Cable glands shall be metric wherever possible, with instrument cable gland connections generally being ISO M20.

Cables glands shall be double compression type and shall be manufactured from marine grade brass. For offshore use and also for aluminium enclosures, cable glands shall be nickel plated. For aluminium wired armour cables, aluminium cable glands shall be used.

All cable glands shall be installed complete with an earth tag.

Cable glands in hazardous area shall comply with the following minimum requirements:

a. Cable glands shall be designed and manufactured in conformance to IEC 60079 series of standards, EN 62444, and BS 6121-1.

b. Cables glands shall be double compression type.

c. Cable glands shall be manufactured from marine grade brass. For offshore use and for aluminium enclosures cable glands shall be nickel plated. For aluminium wired armour cables, aluminium cable gland shall be used.

d. All cable glands shall have an earth tag.

e. Cable glands in hazardous area.

f. shall be dual certified Ex db and EX eb.

g. shall be certified to the IECEx 02 scheme in conformance to IEC 60079.

h. For standardisation purposes, and to reduce the risk of errors, the same “Ex” glands shall be adopted for all plant areas.

i. Non-metallic cable glands may be used with non-metallic termination boxes to terminate braided or non-armoured cable indoors when approved by COMPANY.

13.6 Cable Tray and Rack

Cabling shall run on cable ladders or cable trays.

Cable ladder and tray shall have spare capacity for an additional 20% cables.

Cables which leave main tray routes for connection to motors, pushbutton stations etc. shall be installed on tray, channel or other supports between the main cable tray and the equipment.

Cable racks shall be ladder type.

Material for racks and trays shall be selected from the following, conforming to the application and environment:

a. 316L Stainless Steel for offshore and coastal applications.

b. Steel, hot dip galvanised after fabrication for outdoor applications.

c. Mill galvanised steel for indoor, non-corrosive applications.

d. Glass Reinforced Polyester for corrosive applications.

Material selection for applications is subject to Company approval.

Contractor shall specify cable rack routes for ladder rack over 150 mm (6 in) wide on drawings, and plant model including supports where applicable and maintaining separation.

Supports for mounting cable trays and cable ladders shall be designed for the application, from the following:

a. Pre-fabricated, welded to and finished with structural steel.

b. Pre-fabricated stainless steel, bolted to structure.

c. Pre-fabricated, galvanised steel, bolted to structure.

Bolts, nuts, and washers, etc. shall be 316 / 316L Stainless Steel.

Shake proof spring washers shall be installed at bolted connections.

Junction pieces, bends etc. used in runs of tray and rack shall be standard components supplied by the same supplier as the rack or tray.

Cable rack and tray shall be:

a. Self-supporting between holding brackets without deformation after installation of cables.

b. Not supported from process piping.

c. Designed to carry 90 kg (200 lb) concentrated load at mid-point of span without permanent deformation.

d. If support brackets cannot be provided at the required spacing, and to avoid deformation, the tray may be framed in angle steel of sections consistent with the total weight involved.

e. Designed for loads including ice, wind, and snow for outdoor installations,

f. Supported at maximum 2 m (6 ft) intervals for rack and 1 m (3 ft) intervals for tray.

g. Designed to ensure electrical continuity throughout (for metal systems) through rack and tray bonding.

h. Designed to ensure water cannot collect.

Protective removable covers in the same material as the tray shall be provided for cables in trays subject to damage from falling objects or liquids.

Cables shall be routed to minimise exposure to sunlight.

Cable tray or ladders exposed to sun or where mechanical damage is likely to occur during plant maintenance, shall be provided with covers to protect the cable.

Dissimilar metals (e.g. racks and rack supports) shall be separated to avoid electrolytic corrosion.

If fire resisting qualities are required, the cable supports and fixing arrangements shall have the same durability.

Instrumentation wiring and tubing shall be routed to minimise fire damage.

Main instrument wiring runs shall not be run in the vicinity of fire prone areas, such as hot oil pumps.

If the installation of electrical equipment, tray or trunking on to fireproofed members cannot be avoided, support brackets shall be installed, before fireproofing material is applied.

Design of tray shall be to avoid the need for fireproofing but if required, fireproofing shall be applied as per the HSE requirements.

If pneumatic or hydraulic signal tubing is routed in the same cable tray with low voltage power cable, the tray shall have partitions to separate tubing and cables.

Pneumatic or hydraulic supplies containing combustible materials shall not be routed in the tray with signal and power cabling.

13.7 Junction Boxes

Junction boxes for instrument cables shall be installed at the locations indicated on the lay-out drawings in such a way that they are permanently accessible.

The ideal location for junction boxes is against the supports of main pipe rack. For open areas such as tank farms, etc. they should be supported on substantial frames. Junction boxes located in the units shall be distributed in order to place them as near as possible to the centre of their associated instruments.

The junction boxes shall be marked externally with suitable nameplates. All junction boxes shall be kept closed when not being worked upon. Junction boxes should be installed before the start of cable laying.

Junction box material shall be 316L stainless steel. 316L stainless steel junction boxes need not be painted unless specific project has protection requirements due to external corrosion. They will be built in accordance with safety requirements and will be fitted with cable glands (bottom mounted). Cables glands shall be brass, double compression type.

Junction boxes will be fitted with an external earth terminal.

The minimum degree of protection for junction boxes shall be IP 65. Junction boxes installed in Zones 1 and 2 shall be rated Ex ‘eb’.

Separate junction boxes shall be used for different systems like ESD, ICSS, F&G, MMS, etc. Mixing the signals for different systems in one JB shall be avoided. Also, within one system, separate junction boxes shall be used for different types signals e.g. Analogue (4-20 mA) and 24 V DC, thermocouple, IS and NIS, etc. In any case, mixing of AC and DC, low voltage and high voltage in one JB shall be avoided. Redundant signals shall be wired to different JBs.

All branch or package cables shall be side entry to junction box and all main or plant cable shall be bottom entry to junction box.

There shall be 20% spare terminals and branch cable entries for future use. Spare cable entries of the JB shall be plugged by using hazardous area certified stopping plugs same IP rating.

The terminals shall be blue and the junction box clearly labelled “IS” for intrinsically safe service.

Junction box design and installation shall incorporate cable entry requirements as follows:

a. For site run and multi-pair cables, cable entries shall be from the bottom of the junction box.

b. For package and instrument cables, cable entries shall be from the side of the junction box.

c. Unused or spare cable entries shall be plugged or covered with a certified plug.

As a minimum Smart Junction Boxes / Remote I/O shall meet following requirements:

a. All I/O cards and Components (except barriers and terminals) shall be redundant with redundant power and communication in such a way that failure of a single component or replacement of the failed component shall not interrupt operation.

b. Enclosure shall be certified as suitable for installation in an area as per section 7.2.10.3 Area Classification.

c. IS and Non-IS Smart Junction Boxes / Remote I/O shall be segregated.

d. Where permitted as part of the certification, a separate terminal box to terminate field instrument cables is allowed.

e. Shall have temperature, humidity, smoke, door open status monitoring and provide a common alarm to ICSS.

13.8 Instrument Fireproofing

Fireproofing of instrumentation shall be avoided through process and layout design. If fireproofing of instrumentation is unavoidable, then the corporate requirements shall be followed.

13.9 Electrical Power Supplies

Instrument electrical systems shall be designed to ensure that a single failure of supply or equipment shall not cause a failure of more than one instrument.

All process control instrumentation, gas chromatographs, analysers, emission monitoring devices, PLCs, burner management systems, distributed control systems; metering systems, stand-alone controllers, computational devices, annunciators, fire and gas detection/safety systems, ICSS systems, and emergency shutdown (ESD) systems shall be powered by a two independent UPS power supplies.

UPS systems powering critical instrumentation shall consist of redundant UPS units.

Power wiring for field instruments, two-wire analogue transmission loops, field switch contacts, etc., shall be individually fused and provided with a means of disconnecting the power without disturbing terminated wiring (e.g., knife-switch-type terminal blocks).

Power supply capacities shall be rated to take account of any anticipated future expansion requirements.

13.10 Earthing

13.10.1 General Earthing Requirements

Instrument Earthing systems may comprise of two or three of the following levels:

a. Safety Earth (ELE) - also called as Plant Earth or Protective Earth or Electrical Earth.

b. Instrument Earth (INE) - also called Clean Earth or System Earth.

c. Intrinsically Safety Earth (ISE) - also called Barrier Earth or Zener Barrier Earth.

Notes:

1. Power supply neutral Earthing for Power supply systems to Instruments or Instrument panels shall be addressed separately as a project practice, since the general practice is to have “floating” mode power supply to Instrument or instrument panels to avoid fault shutdowns due to noise voltages induced in the circuit.

Earthing requirements shall follow IEC TR 61000-5-2 and IEC 60364. COMPANY facilities may include a single integrated plant earthing system with a final single point tie-back of all INE and ISE to ELE(s) or a fully segregated INE and ISE with separate earth pits / rods / insulated structure. A typical earthing diagram is provided in Appendix 2.

13.10.2 Cabinet Earthing Requirements

Earthing requirements for within cabinets are identified below:

a. The instrument cable screens shall be earthed at one end only at the equipment room marshalling or I/O interface cabinet, while the screens shall be left tied back and insulated at the field end of the measuring element, transducer or transmitter. The screen continuity shall be maintained from the field instrument to the marshalling or equipment cabinet and shall be continuous through field junction boxes or intermediate terminations.

b. The equipment room marshalling cabinets shall have the instrument earth bar and intrinsically safe earth bar insulated from the cabinet enclosures. The instrument earth and intrinsically safe earth bars inside the cabinets shall be separately connected back to the main instrument earth and main intrinsically safe earth system using typically 70mm^2 cables.

c. The cabinet enclosures shall be separately connected to the safety earth bar and then connected back to the main safety earth system using a 70mm^2 cable.

d. Each individual and overall screen shall be terminated within the Instrument Earth (INE) or Intrinsically Safe Earth (ISE) terminal strip.

e. Separate but linked individual and overall screen terminals are then connected back to either the separate Instrument Earth (INE) or Intrinsically Safe Earth (ISE) bar.

f. INE from each cabinet shall be linked to the insulated main instrument earth as per AGES-GL-02-001 Electrical Engineering Design Guideline and Electrical power, control and earthing cables specification.

g. Lead sheath (when provided), steel wire armouring and metal wire braiding of signal cables shall at each termination be connected to safety earth.

h. Mounting bolts of instrument housings shall be fitted with two shark rings to ensure a very low resistance to structure.

i. Ungrounded Thermocouple screens shall be insulated in the thermocouple head and earthed at the instrument earth at marshalling cabinet.

j. Grounded thermocouple (e.g. skin thermocouples) when used, shall be provided with galvanic optical isolator at the control room end before the marshalling cabinet. The earthing of separate screened cable after the isolator shall be at the instrument earth at the marshalling cabinet.

k. Screened cables for Machinery Monitoring System (MMS) shall follow manufacturer’s guidelines.

l. Cable armour shall be earthed to metallic enclosures by an earthing ring or bond leading to Safety Earth.

m. Metal enclosures and junction boxes shall be earthed to their local steelwork support by typically 6mm^2 earthing cable, earth bolt and tag washer.

n. Metallic sections of a Fibre re-enforced Polyester Junction box shall be earthed to their local steelwork support by 6mm^2 earthing cable, earth bolt and tag washer.

o. Gland plates within enclosures and junction boxes shall be linked internally to the local steelwork earthing connection point.

Notes:

1. Typically, field instruments do not have insulated connection facilities for the screen. The screen shall be tied back and insulated with a protective sleeve and left (open) unconnected with the same offset length as the screen wires.
2. Lightning arrestors used for DC signals installed at the transmitter end may also require field safety earthing of the shield. Such transmitters shall also be provided with galvanic optical isolator at the control room end before the marshalling cabinet. The earthing of a separate screened cable after the isolator shall be at the instrument earth at the marshalling cabinet.

Refer to the Earthing Drawing in Appendix 2 illustrating the earthing requirements.

14 INSTRUMENT INSTALLATION

14.1 General

Instrument accessibility shall be addressed during the 3D-model reviews.

Instrument accessibility should be optimized as reasonably practicable and within reasonable cost.

Instruments in safety instrumented function (SIF) service with a proof test interval of two years or less shall be permanently accessible.

Control points, electrical push buttons, switches, control panels and junction boxes shall be located at optimum height between 850mm to 1300mm without need to use ladders, scaffolding or to remove any piping, doors or floor plates and without need to enter the enclosure or to have a shutdown.

14.2 Package Equipment Instrumentation

See AGES-SP-04-007 Instrumentation for Packaged Equipment.

14.3 Instrument Process Connections

Instrument process connections shall comply with the following, unless otherwise stated by COMPANY:

Table 14.1 – Instrument Process Connections - Minimum Sizes

Instrument Device	Connection on Equipment			Instrument Connection	Vent and Drain
	Pressure Vessel	Piping	Storage Tank		
Pressure Gauge	1 ½” RF Flg	*½” NPT	2” RF Flg	½”	½”
Press Transmitter / Press. Switch (Note 6)	1 ½” RF Flg	*½” NPT	2” RF Flg	½”	½”
Differential Pressure Transmitter	1 ½” RF Flg	*½” NPT	2” RF Flg	½”	½”
Level Displacer (Note 1)	4” RF Flg	4” Flg	4” RF Flg	4”	2” Flg
Level switch (Notes 1 & 6)	4” RF Flg	4” Flg	4” RF Flg	4”	2” Flg
Gauge Glass (Note 3)	2” RF Flg	2” Flg	2” RF Flg	¾”	½”
Diff Pressure Transmitter	2” RF Flg	2” Flg	2” RF Flg	½”	½”
Thermowell	1 ½” RF Flg	1-½” Flg	2” RF Flg	2” RF Flg	N/A
Local Indicator	1 ½” RF Flg	1-½” Flg	2” RF Flg	To suit installation	N/A
Thermocouple	1 ½” RF Flg	1-½” Flg	2” RF Flg	To suit installation	N/A
RTD	1 ½” RF Flg	1-½” Flg	2” RF Flg	To suit installation	N/A
Filled Bulb	1 ½” RF Flg	1-½” Flg	2” RF Flg	To suit installation	N/A
In-Line Indicator	N/A	Line size	N/A	N/A	N/A
Rotameter (Note 2)	N/A	Line size	N/A	Line Size	N/A
Annubar	N/A	3” RF Flg	N/A	Vendor	N/A
Analyzer	2” RF Flg	2” RF Flg	2” RF Flg	Vendor	N/A
Guided Wave Radar	2” RF Flg	2” RF Flg	2” RF Flg	To suit installation	N/A
Non-Contact Radar	4” RF Flg	4” RF Flg	4” RF Flg	To suit installation	N/A
Magnetic Level Gauge	2” RF Flg	2” RF Flg	2” RF Flg	To suit installation	¾”

Notes:

1. An external chamber with 4” RF top flange, 2” RF side flange, and 2” RF vent and drain flanges shall be provided.
2. Confirm sizing with meter capacity and measurement requirements.
3. Gauge valve process connection is ¾“ MNPT. Gauge glass chamber connection is ½” FNPT. Flanged gauge valves shall be used where required per vessel trim class.
4. In general instruments and valves should follow the project piping specification. Process flange connections shall be ASME Class150 minimum rating on pipes, and ASME Class 300 minimum on vessels and tanks. All control valves shall be ASME Class 300 minimum

5. Minimum flange top entry connection on Vessels, Tanks and external chamber bridles shall be 4” NB. External bridle chambers shall have 2” NB side entry process connections.
6. Switches shall be avoided and require COMPANY approval. All switch device functions shall be implemented using electronic analogue transmitters with the switching functions incorporated within the ICSS or UCP.
7. Instrument impulse tubing shall be 12mm O.D., 0.89 mm minimum wall thickness, SS-316L. However, selection of materials shall be chosen based on the process condition.
8. Instrument pneumatic signal air supply tubing minimum size 6mm O.D., 0.89 mm minimum wall thickness, SS-316L.
9. Where listed above NPT connections shall be used when permitted by the project specifications.
10. Where piping supplies a flange, a lap joint style tubing adapter or flanged style gauge mount shall be used.

In the event that it is impractical or unreasonable to apply the above process connection sizes due to application or access constraints, the package SUPPLIER shall request COMPANY approval to deviate from these requirements stating his alternative connection method.

All instruments shall be installed so that accuracy, reliability or maintainability shall not be impaired due to vibration

14.4 Instrument Process Piping

Instrument piping shall be arranged to avoid measurement error caused by condensate build-up in gas service, air/vapor entrapment in liquid service, or overheating of the instrument in hot fluid service.

Consideration shall be given to readability, accessibility, ease of maintenance, and to avoid blocking of accessories.

Close-coupled pressure gauges shall have their line taps on top of horizontal line when feasible. If it is more convenient for design, accessibility, or readability to be on a vertical line or on the side of a horizontal line, tap will be oriented to avoid having the gauge extend into narrow walkways.

Indicating instruments shall be installed to be readable from their associated manual control device and for operating convenience.

A line class primary block valve shall be provided at each process connection.

Piping take off always includes isolation valve at piping tap (manifold cannot be used as piping isolation).

The instrument process piping shall slope up or down toward the instrument at least 2.5 cm per 30 cm.

All instrument piping shall be self-supporting when the instrument is removed for maintenance. Use tube unions only where necessary on long runs (more than standard tubing length).

Differential pressure instrument leads shall be run together as much as possible.

Selected process services shall have a primary block valve for future instrument installation. The future connection shall be plugged.

For sour and lethal service, instrument drain valves and vent valves shall be connected to closed drain and vent systems. (As shown on P&IDs)

For dirty applications (like boiler steam drum level), drain pots shall be provided.

All process piping shall be 12 mm OD (1.5mm wall).

All PTs, LTs (ΔP type) and PDTs, etc. shall be identified by tags (permanent, engraved, metal plate) at the first isolation valves.

If more than one instrument is connected to the same process connection, then there shall be separate isolation valves for each transmitter. Instrument manifold shall not be considered as an isolation valve.

All PDTs shall have vent/drain facility at both high pressure and low-pressure tapping points.

Suitable tube clamps shall be provided to protect against vibrations.

A separately mounted laminated Traffolyte tag plate, with tag number and service, shall be provided for each instrument. This is in addition to nameplate mounted on instrument body, supplied by instrument vendor. Tag plate shall be white/black/white except in the case of safeguarding systems, where it shall be red/white/red. This tag plate shall be mounted separately, e.g. Instrument stand, and not on instrument itself, so that information on location of instrument is available in case of instrument removal.

Instrument process piping details are described as “close-coupled”, “semi-remote”, or “remote”.

The close-coupled instrument shall be supported by the primary valve and the primary valve is readily accessible. The semi-remote instrument is mounted from 1 to 2 metres from the primary valve and the primary valve is readily accessible.

The remote instrument is mounted more than 2 metres from the primary valve.

All applicable details for each installation shall be examined before work on mounting or piping is started. This is particularly important when sealing or purging is shown on the detail, and when heat tracing or special insulation is indicated.

Sufficient clearance shall be provided for removal of the instrument cover or the instrument enclosure and for access to external adjustments.

Instruments shall be installed as indicated on standard instrument installation details.

14.5 Instrument Air Piping

Tubing installation shall use tube unions only where necessary on long runs. Continuous runs will be preferred.

Tubing shall be adequately supported and protected by the following methods:

a. In raceway or angle bars. (Stainless steel tubing shall never be in contact with galvanized materials)

b. Clipped to protective structural members.

c. Individual tubes 80 cm long can be installed without support.

Main instrument air headers will be shown on piping drawings. Sub- headers will be shown on instrument location plans and installation details. Instrument air supply lines shall be connected to instruments with 1/2” (15mm NB) ball type valve.

Minimum size of sub- header shall be 3/4” (15mm NB).

Air supply to an individual instrument shall be routed directly from air header to shut-off valve at the air-set of the instrument.

Air supply line shall be 3/4” (15mm NB) for 5 instruments and 2 spares.

Air supply line shall be 1” (25mm NB) for 12 instruments and 5 spares.

Air supply line shall be 1 1/2” (40mm NB) for 50 instruments maximum.

Air supply test points for pneumatic supply to test equipment shall be provided for each group of instruments.

Drain valves will be installed at low points.

No quick disconnects will be used.

Spare take-offs will have valves with plugs (15% spare valves).

Each tap on the air header should be numbered to show the instrument, control valve, I/P transducer, etc. connected to it.

14.6 Sunshades

All electronic instruments located in an open area shall be protected with sunshade. Displacer type level instruments shall be protected with a custom - made sunshade.

The shade shall be fixed to the mounting plate in such a way that quick installation and removal is guaranteed.

Sunshade material shall be sun and UV resistant.

14.7 Cable

Cables connected to instruments which have the possibility of an internal release of flammable medium shall be provided with a sealing fitting to prevent liquid/gas transport.

Cable passages/ducts shall be designed such that cable laying and cable pulling is possible within the allowable mechanical properties of the cable. Cable manufacturers' specifications shall be followed with respect to the minimum bending radius and pulling strength of the cables.

Cables shall enter the gland from below to avoid the ingress of water.

Instrument cables shall not be routed along with electrical cables.

All redundant cables shall be routed in diverse routes in different trenches / trays / raise ways and shall not cross each other. Wherever the redundant cables are running in parallel, the cable shall be 9 metres apart from each other, as a minimum. Flags shall be provided for every 5-metre in order to identify the cable route.

Underground instrument signal cables shall be laid in dedicated trenches and their routing shall be indicated by above ground route markers.

Underground cables shall be marked at intervals of 5 m by means of lead or stainless-steel strips. For long stretches marking at 10m to 15 m intervals shall be sufficient.

Underground cable markers shall be of stainless-steel sheet on which the cable number has been printed by means of letter/cipher punches

All cable markers shall be tied to the cable using PVC coated stainless steel cable ties.

14.8 Junction Boxes

Separate cables and junction boxes shall be provided for IS and NIS, ICSS, ESD and Fire & Gas services.

The following segregation shall be provided for input and output (I/O) signals as follows:

System	I/O Type	Cable Segregation	Junction Box Segregation
PCS	AI	Separate	Separate
PCS	AO	Separate	Separate
PCS	DI	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
PCS	DO (24V DC – Non-Inductive)	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
PCS	DO (24V DC –Inductive)	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
ESD	AI	Separate	Separate
ESD	AO	Separate	Separate
ESD	DI	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
ESD	DO (24V DC – Non-Inductive)	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
ESD	DO (24V DC – Inductive)	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
F&G	AI	Separate	Separate
F&G	DI	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
F&G	MDI	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
F&G	MDO	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
F&G	DO (24V DC – Non-Inductive)	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals
F&G	DO (24V DC – Inductive)	Separate	Same J/B allowable for all digital I/O Segregate inductive DO's on different sections of terminals

Electrical and instrument cables shall be run on separate trays or ladders or in separate trenches or troughs. In a multi-purpose cable trench a division wall the full depth of the trench shall be provided. When power cables intersect instrument signal cables, the crossing shall be at right angles, with a minimum separation distance of 300mm.

IS, Non-IS, Fire and Gas, Network, CCTV, PAGA, Security Access Control and PABX shall be run in separate trays, ladder and routes to avoid interference.

Where an earth bond cannot be assured by the mounting arrangement, a separate earth conductor shall be run from the equipment case to the dirty earth bar.

Screens shall be insulated from one another and earthed only at one point as indicated below:

For IS circuits, at the IS earth bar, for non-IS circuits, at the panel reference bar.

15 INSTRUMENT RECEIVING, RECEIVING, STORAGE AND INSTALLATION

Contractor shall be responsible for:

a. Taking delivery of "Company / CONTRACTOR supplied" equipment and materials

b. Secure storage of all items in environmentally controlled, vibration free conditions in conformance to Contractor's procedure.

c. Continuous stores monitoring and reporting equipment and material usage.

d. Advising Company of any anticipated shortages to avert delays.

Upon receipt, instruments shall be checked for:

a. Conformance to Purchase Order specifications.

b. Correct tagging.

c. Shipping damage.

d. Relevant documentation (installation and handling instructions).

After inspection, instruments shall be:

a. Replaced in their original factory boxes.

b. Correctly tagged.

c. Stored on shelves in a dry, enclosed area.

Prior to installation, instruments shall be stored in a protected and secure environment to prevent ingress of moisture.

Integrity of sealed protective covers shall be maintained during storage.

Installed instruments shall be covered using polyethylene throughout construction activities, except during actual work on the instrument.

Coverings shall be kept in place and integrity of protection maintained until final commissioning in order to protect the device from environmental factors.

If equipment items require special treatment during storage, shipment and installation, Contractor shall follow the specific manufacturer's instructions.

After installation, vulnerable electrical, instrument, fire and gas, and communications equipment shall be provided with temporary mechanical protection in order to avoid damage to them during construction and activities prior to the commencement of pre-commissioning and commissioning activities.

Instrument and Control room rooms shall be completed with functioning HVAC, whether this is temporary or permanent, to maintain the climate and control dust, etc. to protect equipment before installation of equipment.

15.1 Instruments

Electronic instruments shall be stored in a dust-free room between 8°C and 30°C (45°F and 86°F) or in conformance to manufacturer's procedure if more onerous.

Pneumatic instruments shall be stored in a dry area, protected from the elements.

Instruments shall be sealed and stored in plastic wrap, placed in a box with desiccant bags outside the plastic wrapping, and stored indoors.

Heating and air conditioning shall be provided where required.

Lifting or slinging of equipment shall be done using only manufacturer's prescribed lifting methods.

Supply and application of consumables (purging gas, dry air, nitrogen) required for the correct storage and handling of equipment under the care of Contractor shall be the responsibility of Contractor.

Desiccant bags shall be placed inside equipment enclosures during storage.

Pneumatic and electrical openings shall be weatherproofed using protective plastic port plugs if storing instruments prior to and during installation.

Dial thermometers, pressure gauges, and gauge glasses shall be protected against physical damage from construction activities.

Devices may require removal and storage in a dry, enclosed area for protection. In that case, process connections shall be capped or plugged with metal or plastic caps or plugs until the instruments are installed.

15.2 Panels

If labelling is not visible, packaging shall only be opened just enough for identification, then resealed.

Desiccant bags shall be placed inside the packaging before resealing.

Panels shall be placed in a dry, enclosed or protected area with temperature between 8°C and 45°C (45°F and 110°F) unless project documentation specifies otherwise.

Panels with internal heaters shall be energised during storage.

15.3 Tubing

Storage of tubing and fittings for the project shall be managed to avoid any danger of mixing fittings or tube of the wrong size or type.

Only fittings and tubing in conformance to project requirements e.g. size, wall thickness, customary or metric, manufacturer, shall be held in store.

Tubing packages shall be segregated and clearly marked by material, size and wall thickness.

Tube that is deformed, scratched, scored or otherwise marked shall not be used.

15.4 Items Delivered with Equipment

Documentation and other items delivered with equipment shall be retained and stored.

Documents shall be filed by tag number or equipment number where applicable.

Documents for bulk items shall be filed by supplier purchase order number.

Documents may include:

a. Hazardous area certificates.
b. Calibration certificates.
c. Instruction manuals.

Other items shall be identified by tag number or equipment number where applicable or purchase order number for items associated with bulks.

Items shall be stored with associated equipment.

These items may include:

a. Installation tools.

b. Spare parts.

15.5 Chemical Safety Data Sheets

Chemicals received at Company facilities shall have a MSDS.

At time of shipping, MSDS shall be provided for chemicals shipped with instrumentation.

Equipment or materials that contain or are coated with any of the following shall be prominently tagged at openings to indicate nature of contents and precautions for shipping, storage, and handling:

a. Insulating oils.

b. Corrosion inhibitors.

c. Antifreeze solutions.

d. Desiccants.

e. Chemical substances.

f. Hydrocarbon substances.

Before shipment, a current MSDS shall be forwarded to Company for each substance shipped in or with equipment that may be locally regulated and shall be affixed in protective envelopes to the outside of the shipment.

Hazardous MSDS shall comply with local regulations and shall include a statement that the substance is considered hazardous.

PART II

16 PHILOSOPHY

16.1 System Technical Requirements

16.1.1 MAC Concept

The ICSS shall either be part of a Main Automation Contractor (MAC) approach where the Main Automation Contractor is evaluated and selected by ADNOC as part of the pre-FEED activities to realise gains in efficiency, schedule and associated cost, or procured as a package.

The advantage of the approach using a MAC with associated integration of the ICSS is that the MAC is responsible for ensuring integration and operation of the ICSS and associated packages.

Pre-selection of the MAC prior to the FEED stage realises the following:

a. Control and instrumentation can be designed and engineered around a known ICSS, thereby realising savings in schedule and quicker maturing of the design.

b. The design can reach a greater level of maturity at the end of FEED by using the time saved by pre-selecting the ICSS before the start of the FEED phase.

The MAC process is defined by the following documentation:

a. MAC Scope of Work - defines what is required by the MAC.

b. MAC Roles and Responsibilities Matrix - defines the contractual responsibilities by the various parties.

c. MAC Integration - defines the levels of integration for each of the packages and systems.

d. MAC Interfaces - defines the technical interfaces between packages and systems.

e. MAC Functional Design Specifications (FDS) - scope is defined in the MAC Roles and Responsibilities Matrix and these are produced by the MAC during the FEED phase and updated as the project progresses.

The advantage of preparing the FDSs during FEED is that the information for the design and engineering of the ICSS is available during FEED and that all parties can mature the design at a faster rate than would otherwise be the case.

Refer to the corporate requirements covering this approach, including the following documents that cover the requirements of the PCS, ESD/SIS and Fire and Gas systems:

AGES-SP-04-001	Process Control System Specification
AGES-SP-04-003	Fire and Gas System Specification
AGES-SP-04-004	Emergency Shutdown (SIS) System Specification

16.1.2 Instrument Asset Management System (IAMS)

The required Instrumentation Asset Management System shall form an integral part of the Control Systems Network, located in the Main Control Room and each IES. The Instrumentation Asset Management System and software package supplied shall form part of a complete Control System automation solution. The IAMS system will employ the latest field proven technology, enabling the functionality to be met.

The IAMS shall include all required hardware, software and system programming to provide a complete and operational system. This shall comprise the IAMS and workstations, with the required operating system software, and the full set of the system application software to provide the required features, meet industry guidelines, protect personnel safety and reduce the risk of plant accidents.

The IAMS to be supplied as part of the control system. The IAMS shall provide access to HART and Foundation Fieldbus maintenance and diagnostic data for all analogue devices connected to the control system, including devices supplied as part of mechanical packaged equipment. The IAMS shall provide data storage, data analysis, trending, maintenance scheduling and reporting functions without interfering with the Plant control system.

The IAMS shall also support the partial stroke testing (PST) (jog testing) of Emergency Shutdown Valves, in combination with 'Smart' Valve Positioners. The IAMS shall provide valve diagnostic tests including dynamic error bond, drive signal, output signal, and step response and signature curve. This shall be included as part of the 'Smart' positioner functionality to allow for every operation of the ESD valves to be recorded with sufficient information to count towards meeting the functional safety requirements.

The IAMS supply shall cover as a minimum:

a. IAMS to be located in the Main Control Room and each IES
b. Associated Hardware and Peripherals: e.g. Redundant Servers and client workstations.
c. All network interfaces to the control system and other subsystems
d. Associated System Software E.g. Operating System
e. Associated Applications Software e.g. Instrumentation Asset Management Software, Configuration Software and Interface Software
f. Licenses for the Software
g. Compatibility with multi-vender devices

The Control System Vendor shall carry out all system testing for the IAMS system, including FAT, SAT, communication tests and integration tests.

The IAMS data shall be available on the central data historian server for remote performance management.

16.2 General Control Concept

The ICSS interfaces directly and as seamlessly as possible to all package and package control systems as part of the ICSS. The interface shall enable full monitoring and control of these packages from the ICSS with total integration of the Process Control System (PCS), Safety Instrumented Systems (SIS), Fire and Gas Systems (FGS), and associated systems including Pipelines and Subsea.

Interfaces with third party systems shall utilize well proven and reliable interface protocols. All Interfaces shall have redundant hardware configuration with automatic bump less switch-over to the redundant link.

Interface protocols include the following:

Modbus over Ethernet (TCP) shall be utilized where

a. Native timestamp data is not required
b. Possible logic execution is expected
c. Driving the interface link with dedicated module that becomes part of a ICSS controller

All Modbus over Ethernet (TCP) interfaces shall be redundant

OPC shall be utilized where

a. Native time stamp involving bulk process data transfer is required

b. No executive actions are required through the interface

c. Data used for information and further analysis/processing purpose only

The ICSS shall be capable of OPC connectivity as a server as well as a client with other hosts and sub-systems. The OPC link shall be fully redundant hardware configuration with automatic switch-over to the redundant link.

a. OPC servers shall conform to the necessary standard for the data being transferred (Alarm and Events, Data Access, Historical Data Access, Data Exchange).

b. OPC servers shall not use more than 60% of any resource (memory, CPU processing time) at commissioning. Ethernet communications shall not use more than 20% of the available bandwidth at any point on the network.

c. All OPC interfaces including the servers shall be redundant.

The design of all interfaces shall be subject to Company approval.

16.2.1 Island mode of operation

Plant operations are normally controlled and monitored from the Main Control Room. To cover the need for remote operation, the ICSS shall support Island Mode of Operation from a location other than the Main Control Room in the event of a break in the network.

When the affected part of the ICSS enters Island Mode, the following requirements shall be met:

The local ICSS Workstation shall continue to function normally, providing full monitoring and control access to equipment connected to controllers within the location. This includes all ICSS controllers, associated equipment, interfaces and packages.

Functionality shall be maintained despite a break in communications so the plant safety and integrity is not compromised with the safety and fire and gas systems protecting the plant.

16.2.2 Data Communications

Data communications shall utilize the PCN and Safety Networks using dual redundant, continuously monitored fibre optic cable from MCR to plant buildings capable of data transmission over a distance of a minimum of 5000 m. The system shall be capable of automatically switching to the redundant highway on failure without interruption of service.

Topology shall be robust enough not to lead to loss of view / control within the ICSS. Highway communication loss shall not at one location (redundant) shall not lead to loss of view/control of the entire ICSS.

16.2.3 Virtualization of ICSS HMI layer

Virtualization of the platform at HMI layer is to be considered instead of conventional hardware platforms. The Virtualization at HMI layer shall consider all servers and workstations including but not limited to Operator workstations, Engineering workstations, OPC servers, Historian, etc.

Control system vendors are to provide the recommended system requirements for installing and running the virtual estate. The requirements for virtualization of their architecture shall include hardware platform (servers, switches), software (VMS and application OS), and any additional software or hardware required to instigate and manage the complete Virtualized system.

The system shall be able to run multiple virtualized computers (virtual machines) on a single virtualization host computer, thereby reducing the managed hardware, in addition to this the functionality for quick and easy recovery during a failure scenarios shall be available for increased availability of plant operation.

Virtualization software's shall have the functionalities of managing multiple virtualization host computers. User Interface network used for interconnecting virtual machines and thin clients shall be in dual-redundant configuration. It shall also enable the users to monitor the settings and status of the virtualization software, Virtualization software shall also consider live migration function, automatic failure function and in configurations with multiple virtual computers, it shall be possible to add a replication that creates a copy of a virtual machine on another virtualization host computer on a regular basis.

ICSS vendor shall provide all hardware and software support for system virtualization that ensures high availability and maintainability of the system and provides management tools for the virtualized system architecture components. OEM to highlight the tools or pre-packaged virtualization tools to enable ease of implementation and management of the virtual architecture.

The virtualization design shall also address the Island mode of operation

16.2.4 Plant-Wide Network Connectivity (high level interface)

The ICSS shall be interfaced to a higher level local area via one or more dedicated gateways/OPC interface supplied by others for each application. This network integrates the Corporate Process Information & Management System (CPIMS)/Process historian, Corporate Alarm Management System, Integrated Real time Optimizer etc. via independent redundant gateways/OPC interface.

The ICSS shall be capable of OPC connectivity as a server as well as a client with other hosts and sub-systems. The OPC link shall be fully redundant hardware configuration with automatic switch-over to the redundant link.

Design of communications layers shall be as per IEC 62443, with independent and redundant interfaces for each application, and Cyber Security requirements as per Company Corporate policy.

16.2.5 Process Historian within ICSS

ICSS shall be capable of historization of plant data events and alarms with automatic archiving. Archival, system back-up and backup media shall be as per centralized backup solution detailed in Company PCN Security policy.

System shall be capable of displaying both real time and historical trends as follows:

a. Real time trend: The real time trend shall be for a minimum of 1 hour at a sampling rate of 1 second.

b. Historical trend: The historical trend shall be for a minimum period of 60 days.

Historical data shall be stored on a non-volatile memory device such as hard disk. It shall be able to be archived and subsequently recalled.

The available storage shall be sufficient for all analogue points for a period of 60 days at a sampling rate of 1 minute or better. Varying the sampling rate shall make it possible to store more points or for longer periods.

The available storage shall be sufficient for all analogue points for a period of 60 days at the sampling rate of 1 minute or better. Compressed data storage data shall be for the period of one year.

Trend displays shall have minimum features of zoom in / out, time scale compression, x-y plot, calling trend by date, trend value at cursor location etc.

Real time and historical trends shall be possible on any parameter or variable like measured variable, set point, output, calculated value, etc. The trend display shall be single line type or bar graph type. It shall also display information like loop tag, engineering units, span, current value, alarm status, etc. of the trended variable. It shall be possible to display by scrolling or expanding the time base all of the trend data available on the system. Selection of the tag and sampling time for real time and historical trending shall be possible from operator keyboard.

It shall be possible to sample and store data of instantaneous and average values at the intervals mentioned below:

a. At intervals of 1 second or higher for the real time trends

b. At 10 seconds, 1 minute and 10 minutes interval for historical trends

c. 20% of analogues will be sampled at 1 second intervals and 80% of analogues will be sampled at 5 second intervals

Note: Percentages and time interval shown above are general guidelines and and design is subject to Company approval.

16.2.6 System Diagnostics

ICSS shall cover diagnostics displays for the ICSS and third-party sub systems.

All active components in the ICSS and third party sub-systems shall be included in the system diagnostics (power, I/O, controller, communitarian modules, interface modules etc.) with the failure of any such active components in the ICSS being displayed and alarmed to the operator.

16.2.7 Controller & I/O segregation

Controller segregation shall follow the below guidelines

a. Unit wise segregation shall be followed

b. In case one unit has dependency on other units in the same train (meaning multiple units trip due to unavailability an unit); then units can be combined within the same controller, provided the controller performance criteria is met in all aspects

The following rules shall be strictly applied regardless of the number of I/O channels (8, 16 or 32). The underlying philosophy is to avoid accidentally losing duty and standby equipment when a single card becomes faulty. However, since increasing the number of cards also increases the failure rate and thereby reduces availability, following this principle, the auxiliaries of major equipment such as pumps, motors, air fin coolers, heaters of duty equipment shall be on one card to facilitate maintenance on the card or equipment without any upset for standby equipment.

When an equipment A has a spare B, inputs and outputs (DCS) related to A and B shall be on separate cards and, where possible, in separate controllers.

Signals and commands of Duty/Standby equipment shall be fully separated in the ICSS hardware and software design. If the functional logic between duty/standby equipment requires communication between controllers, the peer-to-peer capability of the controllers shall be utilized.

In utility units, all equipment or packaged units are critical to utility production: When two equipment items produce the same utility (steam generation, instrument air, nitrogen etc.) they shall be in different ICSS controllers. Other utility units shall be spread to optimize system resource utilization

In order to satisfy the above requirements, CONTRACTOR shall develop a detailed I/O allocation philosophy that shall be reviewed and approved by the COMPANY. Compliance with the agreed philosophy shall be required to satisfy the above requirements

16.3 Integrated Control and Safety System (ICSS)

16.3.1 General

The ICSS shall be supplied comprising of PCS, ESD and F&G. The purpose of this specification is to explain how the operator shall use the ICSS and the associated control room equipment to operate and control the plant.

The operator workstation has a number of display facilities available to monitor and control the plant operation:

Graphic displays give access to parameters monitored and controlled by operator in normal operation;

a. Mimics;

b. Alarm displays;

c. Group displays give access to all analogue loops as well as to control elements for which the access is infrequent (valve jogging...);

d. Trend displays;

e. Reports; and

f. Loop detail (point details) display.

The ICSS is the main operator interface to all plant control and monitoring systems. In addition to the PCS controls, operator shall have seamless access to the ESD/SIS system, SMC, anti-surge control systems of compressors, the gas turbine control systems, Fire and Gas system, Tank gauging system, vibration and machine monitoring measurements, other package control systems and advanced process control.

Workstations shall be based upon the latest standard hardware to enable easy replacement and support over the lifecycle of the ICSS.

Access control to the ICSS shall follow the Company Cyber Security Policy with two factor authentication and integrated into the overall corporate systems.

A Maintenance console comprising two Workstations is dedicated for displaying and handling of all related diagnostic alarms across all ICSS systems (PCS, ESD/SIS, and F&G) as well as all the data available in the ICSS for diagnostic of foreign devices. In addition, Maintenance overrides will be invoked from the Maintenance Workstation to override ESD initiators. ESD Valve Jog testing will be scheduled from the Operator Workstations and the results of the jog test will be logged and displayed on the Maintenance workstations.

Access to the Engineering levels for modification of programs, sequential programming, regulatory loop configuration, alarm set-point changes and other engineering functions shall be strictly controlled and managed in conjunction with the supplier of the ICSS. Security keys/password protection shall be provided to access the engineering configuration data.

An Emergency Control Centre comprising two Workstations and two wall mounted Large Screen Displays similar to those supplied for the Operator Consoles will allow monitoring of the complete Process and Utilities plant in the event of an emergency. These workstations will be used for monitoring only and will not be used for control or configuration.

Each IES or remote instrument shelter shall contain an ICSS console for maintenance/engineering and operations. Each IES, although integrated in the overall architecture, will be able to function autonomously in the event of a network or gateway failure. The architecture shall be designed such that if any control network malfunction renders the MCR inoperable, control shall be seamlessly assumed from any IES. The autonomous functions of each IES shall include Monitoring and Control, Historian, Alarm Management and all process related functions associated with a defined process area.

Cyber Security requirements as per Company Policy and Guidelines shall be applied. Cyber Security requirements shall cover for ICSS and all 3rd party control systems.

The following additional systems will interface with the ICSS to provide a single point of operation and control:

a. Measurement and Actuation

b. Field Transmitters and Switches

c. Actuated valves

d. Motor interfaces

e. Tank Gauging Systems

f. Analysers

g. Machine Monitoring System (MMS)

h. Field cabling systems

i. Basic Control, Monitoring & Safeguarding

j. Gas turbine control systems

k. Steam Turbine Governor and Overspeed Protection systems

l. Compressor anti-surge/performance/load-sharing controls

m. Custody Transfer Metering Systems

n. Burner Management Systems (BMS)

o. Integrated Protective Control Systems (IPCS)

p. Interfaces to Measurement and Actuation Subsystems

Package Unit's operation, control, start-up sequence and safeguarding shall be implemented in the plant ICSS system (PCS, ESD/SIS and F&G).

The Machine Monitoring System, Performance/Anti-surge and Load Sharing Systems shall be stand-alone with redundant data communications interfaces to the ICSS system.

Redundancy of the Control layer:

a. Microprocessor based controllers or controller server systems shall be of a dual redundant configuration. With I/O cards redundant for safety systems. The controllers and I/O cards shall switch over to the back-up card automatically in a bump less way when a failure is detected.

b. Redundancy shall be hardware based, with software configured accordingly.

c. System design and configuration shall be such that a single point failure shall not result in a trip of equipment / sub-unit / portion of the unit / plant when a component fails.

d. Redundant design shall be engineered to avoid a single point failure in the system, from input, output, controller, power supply, and communication interface,

e. Critical HMI layer assets such as ICSS servers, gateways, interface servers, domain controllers, historians, backup servers, switches, etc. shall be 2 x100 % redundant. Operator workstations (OWS) shall be distributed; unavailability of one OWS shall not impact the operator plant control capabilities.

16.3.2 Machine Monitoring System

A machinery monitoring system (MMS) shall be provided for the plant/asset, including vibration sensors, temperature probes, key-phasers, accelerometers, etc. The MMS system shall utilize the latest proven hardware & software configurations available, such as Bently Nevada 3500 series / System 1 or equivalent system from an approved COMPANY supplier. Depending upon the application, parts of the system and equipment may be supplied by the package supplier. For example, a gas turbine package.

16.3.3 Performance/Anti-surge and Load Sharing System

The systems shall have provision for hardwiring of critical signals and commands to the PCS and/or ESD/SIS Systems. Note that the supplier of the equipment and the ICSS Supplier is responsible for ensuring that the systems are integrated into the ICSS.

16.3.4 Advanced Process Control

Advanced Process Control includes the following:

a. Multi-Variable Control System (MVC)
b. Plant Information Management System
c. Training system provided with workstations the same as the operator workstations including controls, I/O cards, and communication cards (at least one card/module of every type used in the main system shall be used) but shall be an independent system and not part of ICSS network.

16.3.5 Alarm Management

The Alarm Management System shall have the following features as a minimum:

Be an integrated part of the ICSS through the alarm and event server.

EEMUA compliant alarm and event reporting. Reporting includes:

a. Top N bad actors (chattering, frequent,)
b. Priority distribution analysis
c. Parent Child alarm analysis
d. Stale alarm analysis
e. Alarm performance indicator analysis
f. Operator actions and interventions analysis
g. Alarm flood analysis
h. Alarm count analysis
i. Alarm analysis per unit/equipment/section of plant
j. Bad Process Variable (PV) alarms
k. Real Time Optimisation (RTO)
l. Identification and analysis report on duplicate alarms
m. In-built export to MS Excel feature

n. Remote access through Internet explorer

The Alarm Management System shall have a storage capacity to store data locally as well as remotely without intermediate archiving to provide operation in the event of network interruptions.

The supplied Alarm Management System shall be capable of filtering alarms/events (this facility shall be available from the ICSS) based on the following criteria:

a. Area

b. Unit

c. Equipment

d. Type

e. Priority level

f. Start date/time and End date/time

g. Tag number

h. Events or alarms

i. Messages

The AMS shall also have First-out and sequence event recording capability. Alarm monitoring and filtering capabilities will also be available at the ICSS.

16.3.6 Other Facilities

16.3.6.1 General Description

Oil and gas production assets can be broadly classified as follows:

a. Production assets based on the PAD / cluster concept.

b. Production assets based on mixed development concept.

c. Pipelines and terminals.

Production assets have oil and gas production wells that are either naturally flowing or artificially lifted together with a variety of injection wells (gas, water, water-alternate-gas).

16.3.6.2 PAD / Cluster based Production

The Central Processing Plant (CPP) serves as the central gathering / processing facility for the well production fluid received from the individual clusters. Each cluster has an associated well PAD comprising of production and / or injection wells and remotely located wells.

Some of the clusters are not directly connected to CPP but are connected with other clusters to co-mingled production lines which connect to CPP.

For clusters and wells the control system is based upon an ICSS with local workstations with all the clusters WHCPs controlling multiple wells and implementing well related interlocks / safety functions using Cluster PLCs and ESD Logic Solvers.

Cluster systems interface to the CPP ICSS is via a network. Most of the cluster systems are connected to the CPP via the SDH network.

Cluster systems interface to packages, electrical and other systems using data interfaces and hardwired signals.

Cluster wells testing uses Multi Phase Flow Meters (MPFMs) or a Test Separator.

A Climatically controlled, safe area located Instrument Equipment Shelter (IES) is provided for each cluster wherein all panels, workstations, consoles, and MMI are located.

16.3.6.3 Remote and Water Injection Wells

Remote wells shall be provided with well head instrumentation, WHCP, PLC and ESD / SIS logic solver with fibre optic interface to PAD / RDS / CDS systems.

Water Injection wells are implemented as remote wells based upon the PAD based design and are connected to the respective PAD ICSS.

16.3.6.4 Well Head Control Panels

The Well Head Control Panel (WHCP) shall be interfaced to ICSS and for monitoring and operating all wells, the ICSS operator interface is located in the MCR. Well Head control system shall also be able to be operated locally.

Company ICSS shall be extended to provide operator interface to Well Operator.

Separate hardwired shutdown switches shall be provided to send a shutdown command to the Well Head Control Panel (WHCP) without relying on the ICSS; the indication of alarms on alarm windows is used to allow the operator to see at a glance the well status.

17 GENERAL CONTROL PHILOSOPHY

In general, centralized plant control utilizing an Integrated Control and Safety System (ICSS) from the Main Control Room is required along with safe area located, climatically controlled Instrument Equipment Shelters (IESs) located at convenient places in close proximity to the plant to house all instrument racks/panels, etc.

Only control network and few dedicated hardwired cables shall be run to the Main Control Room. Otherwise all instrument cables shall be terminated in IESs. MCR shall have all operational control consoles and enable full start-up, monitoring, control and shutdown of the plant units and package/equipment. IESs shall be normally unmanned.

Control and monitoring functions shall be performed on package control system and/or ICSS. All the Control & Monitoring Functions of the package equipment shall be performed from ICSS Operational consoles.

For package control systems, CONTRACTOR shall ensure the data and functionality of the package is replicated in the plant ICSS. Integration of the ICSS into the package shall be as per the Package Integration Philosophy.

17.1 High Priority Control Loops

All control loops defined here shall be redundant.

17.1.1 General

Control loops which discharge product to flare.

Loops which are part of depressurizing system.

Digital outputs from the ICSS with ESD reset action.

Any loop recommended to be redundant by Process team, P&ID review team and HAZOP team

Non-SIL rated safety related loops implemented in the PCS.

Any loop recommended by the SIL review team.

Process train load sharing loops implemented in ICSS.

Air / Fuel ratio loop.

Digital control loops where field equipment is not redundant and failure to operate such equipment impacts process upset/production loss/plant disturbance.

17.1.2 Process Units

Pressure loops on supply headers to other units: feed gas to gas treating units, feed gas to sulphur units.

Feed gas / sales gas at M.P. and L.P. levels including let-down controls.

Feed gas separation level.

Inlet flow of all units.

Amine units:

a. High pressure absorbers level
b. Flash drum level
c. Regenerator overhead pressure
d. Low pressure steam flow to amine regenerator reboilers
e. Amine flash drum overhead pressure (to B.L. and to flare)

Sulphur units:

a. Air/gas ratio
b. Waste heat boiler level
c. Acid gas header pressure control
d. Anti-surge and performance controller of blowers

17.1.3 Utility

Steam let down.

Fuel gas let down.

Waste heat boilers level.

Boilers level.

Steam master pressure.

Instrument air pressure.

Deaerator level.

Air fuel ratio loop.

17.2 Low priority loops

17.2.1 Process

Overhead pressure on columns and vessels.

Steam to reboilers.

Level on compressor feed drums.

18 IMPLEMENTATION CONSTRAINTS

A redundant analogue control loop shall always have a redundant input and output.

In case of cascade loops: when the master loop is defined as redundant, the slave loop shall be redundant.

For redundant split range all outputs shall be redundant.

Analogue input / output, digital input/ output shall use two different cards. Changeover of control from primary to secondary shall be bump less without affecting plant operation.

18.1 Control and Monitoring Systems

The following control and monitoring systems shall be provided in the Main Control Rooms and IESs.

a. ICSS including:
   i. Process Control System
   ii. Fire & Gas Systems
   iii. Emergency Shut Down (ESD/SIS) Systems
b. Public Address/General Alarm (PAGA) and Intercom System
c. CCTV
d. Access Control System (ACS)
e. Intrusion Detection System
f. Electrical Control Systems
g. Analyzers Network System
h. Monitoring System (MMS)
i. Radio system
j. SMC system
k. Gas Turbine Control System
l. Compressor Anti-Surge / Performance / Load Sharing Control System
m. Burner Management System
n. Real Time Information System
o. Alarm Management System
p. Plant Information Management System
q. Time Synchronization

r. Operator Training Simulator
s. Multi-Variable Control System
t. Tank Gauging System
u. Metering System
v. Oil Movement Automation System

18.2 Overview Display

A plant overview with equipment/unit numbers shall be implemented to allow operator access to the equipment/unit overview.

There will be one set of overview process graphics for each process unit, utilities and off sites of the plant. These displays will be based on simplified Process Flow Schemes of the entire unit and will show the main process equipment and contain the following information:

Main flow streams i.e. Feed, Products, etc. with no tag indication.

The stream flow and pressure (when available) at the inlet and outlet of the main units or equipment with no tag indication and other values after review with operation.

On/off valves, ESD valves and control valves will be displayed without tag names. The body and actuator will be dynamic. On/off valves will be targets to access to the jog request commands. All ESD and Control valves shall be dynamic.

A "UU-jog" target will allow the operator to enable the valve jogging facility of unit UU. It will have black letters on red background when jog facility is disabled and white bold bid size letters on red background when jog facility is enabled.

Zone shutdowns will generally be on overviews unless an operating logic prevails and implies their location on an operating graphic.

All pumps and drivers will be static.

Dynamic bar graphs for level indication shall be included on the Overview displays.

The overviews display shall be linked together (next, previous) to cover the operation of a group of units to be defined by operation (e.g. all units operated by one operator).

18.3 Detailed Graphic Display

From the overview, the operator will have access to subsections of the above graphic displaying, in detailed mimic graphics, all relevant analogue control and status values.

The detail displays will be linked together (next, previous) to cover the operation of a group of units to be defined by operation (e.g. all units operated by one operator).

18.4 Packages

For main packages, dedicated detail displays shall be made. The operator will access them from the unit overview or from any detailed graphic that contains the package equipment. Their location in the display hierarchy at detail graphic level or at a lower level will be reviewed with operation.

Package control system dynamic diagnostic graphic displays shall be included in the ICSS. The dynamic diagnostics shall include status of package control system power, Input cards, output cards, controller/processor, communication cards, etc.

18.5 Maintenance Console Graphics

A maintenance console shall be available to display all maintenance diagnostic status of control system hardware including Power, I/O, Controller, Communication etc. & alarms for all systems and package control systems. Diagnostic Graphic shall be proposed by each system vendor for Company approval.

19 DESIGN CRITERIA

19.1 ICSS Graphic philosophy

The design of the HMI shall include the manner in which information will be provided to the operator and the way in which the operator will interact with the system.

The HMI interface and design is covered in the Graphic Design corporate requirements.

The following are considered as the basic requirements for graphics design philosophy:

a. The graphics are to be kept as simple as possible but include all P&ID display requirements and shall enable efficient monitoring and control of the plant.

b. The graphics shall attract operator attention as quickly as possible

c. The operator shall reach the control point with a minimum of keystroke operations.

d. The graphic system shall use a standard approach wherever possible.

The graphic hierarchy shall show different layers of graphics (plant overview / unit overview / units / subunits / packages) and cover the plant sections, PCS, ESD/EDP and Fire and Gas.

19.2 General Aspect of Graphic Display

The graphic title, graphic number, date and time will be shown on each page and in the same position on each graphic preferably on top of display area.

All graphics will be designed on the basis of the latest plant P&ID's.

The following shall be avoided:

a. Solid objects in general but allowed in Machinery graphics which shall be 3D design.

b. Flashing of large objects

c. Reverse video for display other than text.

The following shall not be shown:

a. Start-up lines unless they include instrumentation that must be displayed on the ICSS.

b. Bypass lines having manual valves.

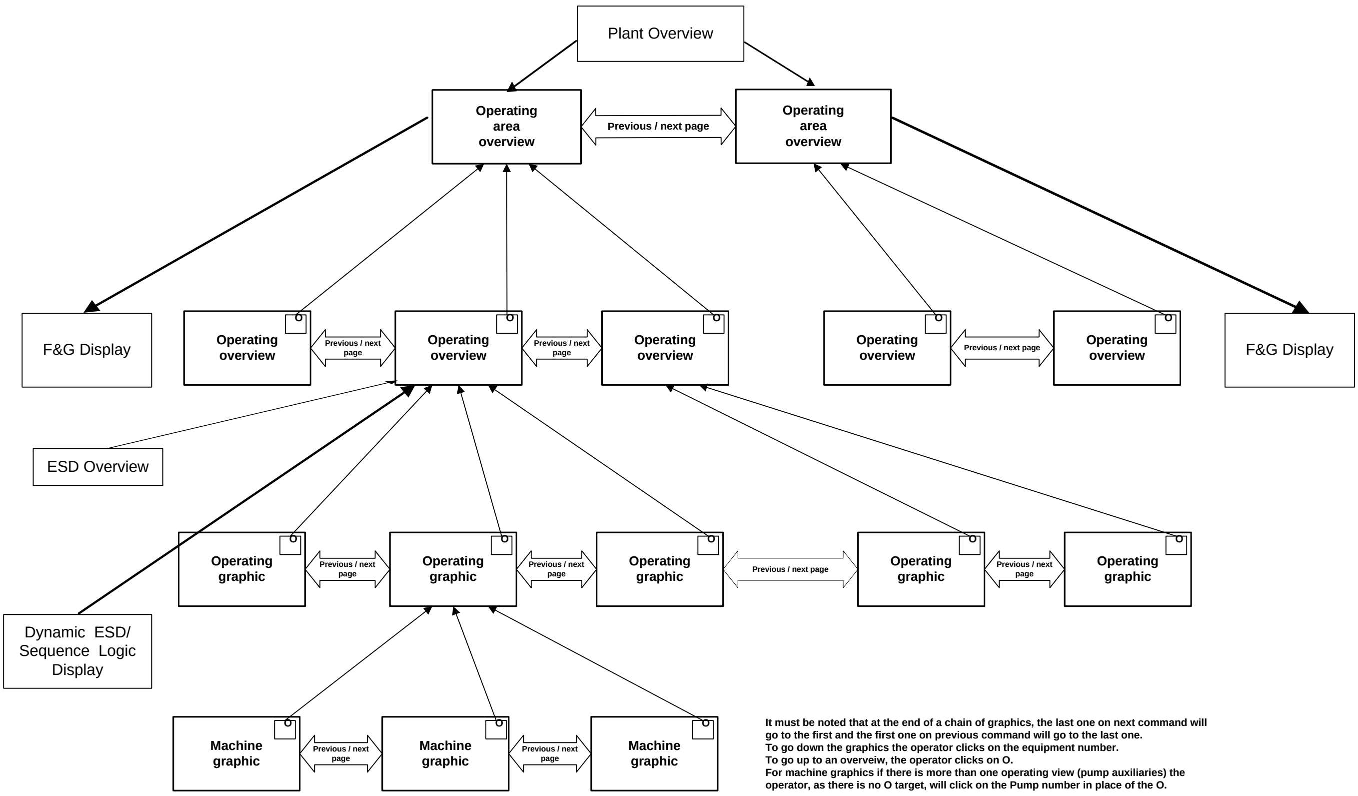
c. Block valves.

Equipment shall be shown only when they are important for the understanding of the operation or are an integral part of the process depicted.

19.3 Graphic Hierarchy

The plant graphics shall be arranged according to the following hierarchy of Area overview, operating overview, operating graphic and machine graphics.

Each display shall have pull down menus to have quick access to important displays.



19.3.1 Plant Overview

This view provides access to entire plant. Area overview: This view provides an access for the operator to the operating overview.

19.3.2 Overview Graphics

Overview graphics are used to navigate from one plant area to another: the process data included in the overview is limited as described in the Design Rules for ICSS Graphics. The operator shall use targets (e.g. main equipment) that allow him to call any operating graphic by a click on the pointing device.

The operator shall be able to navigate between overviews with the previous page and next page keys.

An access to operating graphics by the graphic file name is also possible.

On the overview, the operator has commands limited to the jog request and to the reset of Hardwired Zone shut-downs. ESD/sequence logic displays.

19.3.3 Operating Graphics

Operation of the plant is made from the Operating graphics and the Machine graphics. Each Operating graphic and each Machine graphic shall have:

Physical units are attached to each process parameter displayed on the graphic; these are targeting areas that on a click link to the trend display.

Line arrows at the inlet and outlet of each line on the graphic that by a mouse click go to the preceding or following Operating graphic.

Equipment tags that allow the operator to access to Machine graphics.

19.3.4 Operator Commands

The operators for plant control and monitoring shall generally use the operating and machine graphics. They allow access to all control parameters identified on the process P&ID's. Mouse targets allow the operator to access to a control overlay in the graphic.

In the following sections minimum functions needed are mentioned independent of any ICSS. However, COMPANY shall have right to choose any functions supported by the selected ICSS for the project and will be decided during FDS & CONTRACTOR Detailed Engineering.

These overlays are used for plant operation: at any time, there is maximum four (4) loop that can be displayed as an overlay. When for any reason, the operator needs to have data pertaining to several loops, the operator access shall be made through the group display.

When an operator action is forbidden, the function shall be inhibited, and an indication highlight the status (definition to be proposed and agreed with COMPANY).

Note: In the following sections, the symbol x is used for convenience. X should be replaced by actual measurement parameter such as F, P, T, L, A, etc.

19.3.5 Indicating Controllers (XIC)

Control mode shall be displayed near the control valves. For stand-alone and slave indicating controllers the target is the valve and the measurement/engineering unit will be used as target for trend display. The overlay allows the operator to change mode, set point and to operate in manual.

The target is the measurement. An overlay shall allow the operator to control the master controller.

When two master controllers are linked to one slave, the master controller in control shall be indicated to the operator by an arrow near its measurement.

19.3.6 Manual Loading Stations (HIC)

A click on the valve when the manual loading station is controlling a valve shall allow the operator to access to the valve.

These are minimum functions needed and made independent of any ICSS; however, Company shall have sight to cause any functionality based on the control system selected.

When a hand indicating controller is used as a set point for a loop or as a ratio display, the operator shall be allowed to adjust the set point or the ratio with the overlay. The target is the value of the hand indicating controller in the display.

19.3.7 ESD & ESD Related Switches

The display and reset command of the Hardwired Zone shut down and Emergency De-pressurisation switches is on the overviews. Resets shall also be available from the cause and effect graphic. On every graphic display, there shall be a soft ‘ESD’ Button (which will blink in red when a shutdown occurs) to access ESD display.

19.3.8 ESD sub system shutdowns

ESD sub system shutdown and emergency depressurisation shall be targets. A click on the switches brings up an overlay that allows the operator to shut down and depressurise the subsystem with a confirmation window to avoid accidental trip/depressurisation. It must be noted that the shutdown action is only possible from the overlay or from the ESD/EDP hierarchy graphic.

19.3.9 ESD Reset Commands

These commands only appear when the ESD reset is possible. Their display highlights the target: a click brings up an overlay that allows the operator to reset the logic. It must be noted that the reset action is only possible from the overlay.

Reset commands and status shall also be shown on dynamic power flow sequence/cause & effect ESD display.

19.3.10 Individual Valve Resets

These resets are only available on the graphics

Start-Up Override

Located near the alarm to be by-passed, it shall only be visible when the point is in alarm. A click on the tag shall bring the overlay. The override shall be limited in time according to the parameters set in the ESD. This override is only used for start-up.

19.3.11 Maintenance Override Switch

The maintenance override switch (MOS) as per Emergency Shut Down Philosophy shall be accessible from the ICSS through dedicated displays. Overview of MOS shall be available, which shows the status.

Wherever an MOS in made on any ESD input, a soft button “MOS” available on every display will blink in red and when pressed will show MOS overview display.

When a MOS is set, an indication is given to the operator on the ICSS screen.

19.3.12 Selectors (HS)

For selector switch that are in control loops, the target on the graphic is the switch symbol on the screen. On a click an overlay shall allow the operator to operate the switch.

Other switches which control pumps are integrated in the overlay of the equipment and do not appear on the graphic.

FEED back shall be available and indicated when pump/ESD valve started/ closed/ stopped/opened or failed, on the graphic.

19.3.13 Sequence Operated Valve (KV)

The valve is the target that gives the operator, through an overlay, the control of the valve when the sequence is not in automatic. As this manual operation is abnormal, it is the operator responsibility to check that the valve position change is safe; for selected safety conditions for which the interlock is coded in the ICSS, the operator action shall be blocked if the interlocking condition is not met.

19.3.14 Sequence Control

A dedicated interface is used to allow the operator to access to the control of sequences. As it is tailored for each sequence, it shall be described in the detail sequence functional analysis issued during the detail design. A dedicated display shall be designed indicating the sequence dynamically. Both ESD cause & effect and sequence logic implemented in ESD system/package control system/ICSS control system shall have all the information available on ICSS and shown graphically through on power flow dynamic displays.

19.3.15 ON / OFF Valve (XV)

The valve is the target that gives the operator the control of the valve position if required on the P&ID and if the valve is not interlocked by an ESD sequence. If the valve is interlocked, the magenta colour of the actuator on the graphic shall advise the operator.

For other commands that are not commonly used by the operator, the group display shall be used (jogging request). All jogging requests shall only be conducted from the Maintenance console workstations and accessed from one or several dedicated groups or graphics.

To request a jogging the operator shall go to the unit overview where a jogging request target shall be displayed. After the request is made by the operator, he shall have a time window during which any jogging in the unit can be done by the operator.

19.3.16 Depressurising Valve (XV)

Normal operating commands required on the P&ID's are available through the overlay on the graphics which appears when the operator clicks on the valve.

Commands for which the access is infrequent such as the jogging command are available on the group display.

19.3.17 Pump

Main operating commands required on the P&IDs/Typicals/Specifications/data sheets are only available through the overlay on the graphics which is accessed by the pump symbol used as a target. When a duty/standby select is implemented, the operator shall go to the group display to operate the pump switch-over with the duty / select switch. When a command is not required on the P&ID, it is not available on any ICSS display. But subject to the operation requirement a static pump may be shown on the graphic or a dynamic pump if feedback is available, when no start/stop are used.

For the pumps feedback shall be available through PCS and shall be shown dynamically on the pump symbol shown on the graphic display.

19.3.18 Motor Operated Valves

For MOVs, all commands required on the P&IDs/Typicals/Specifications/data sheets or on the MOV Spec. are only available through the overlay on the graphic that appears after a click on the valve, open/close/inching/stop etc.

19.3.19 APC Functions

All operators related functions for APC shall be through ICSS. Required intervention for APC related to the operator shall be available in the ICSS graphics.

20 GROUP DISPLAYS

This display is used to make significant adjustments to the plant operating parameters when several control loops are tightly related. It can be seen as emulation in the ICSS of a conventional panel display.

As a group display may have loops belonging to several graphics, a target on the display shall allow the operator to go to the overview.

20.1 General Arrangement

The group display shall allow, typically, 8 preconfigured points to be displayed adjacent to each other on a single graphic page in individual “faceplate” zones. A group display would typically display all points associated with one or more associated control loops.

The limited number of analogue loops on the group display does not allow to use it as the main operator access which is the operating graphic.

Note: In the following sections, the symbol x is used for convenience. X should be replaced by actual measurement parameter such as F, P, T, L, A, etc.

20.2 Indicator (XI)

An indicator is displayed on a zone with a vertical bar graph showing the input.

20.3 Indicating Controller (XIC)

An indicator controller is displayed on a zone with a vertical bar graph showing the input and a horizontal bar graph showing the output; it has all controls required for the loop.

20.4 Manual Loading Stations (HIC)

A manual indicator controller is displayed on a full zone with a vertical bar graph to display the output of the manual loading station. When connected to a valve the display shall be 0 to 100%. When used as a set point for a control loop, the physical value shall be displayed.

20.5 ESD/EDP Related Switches

20.5.1 ESD/EDP Sub System Shutdowns

These ESD switches are only available from operating graphics.

20.5.2 ESD/EDP Reset Commands

These ESD switches are only available from operating graphics.

20.5.3 Individual Valve Resets

These resets are only available from operating graphics.

20.6 Selector (XHS)

A half zone shall be used for the operation of switches linked to analogue control loops to switch controllers, valves. No display is available on group displays for other switches such as: ESD switches, reset switches.

20.7 Sequence Operated Valves (KV)

No display is available on the group display as all functions on the P&IDs, required to operate the valve when the sequence is not in automatic, shall be accessed from the overlay on the graphics.

20.7.1 Sequence

All sequence controls are made from the operating graphics

20.8 ON / OFF Valve (XV)

All commands required on the P&IDs are only available through the overlay on the graphics. For jog testing a dedicated display shall be used as the standard group display only allows the use of full- size faceplates.

20.9 Depressurising Valve (XV)

All functions required on the P&IDs shall be accessed from the overlay on the graphics. For jog testing a dedicated display shall be used as the standard group display only allows the use of full-size faceplates.

20.10 Pump

Start / Stop commands and duty select required on the P&IDs are only available through the overlay on the graphics.

20.11 Motor Operated Valve

For MOVs, all commands required on the P&ID's are only available through the overlay on the graphics.

20.12 Control Valve

The group display will show the controller and associated points for the control valve. All functions required on the P&ID's shall be accessed from the overlay on the graphics.

20.13 Equipment

The shape of the equipment to be displayed will be the same as that shown on the P&ID. All major equipment will be displayed: vessels, pumps, columns, compressors.

Vessel liquid levels shall be "live" to reflect the measurements of the liquid. A vertical bar graph (5 to 8 mm wide) will be used to indicate levels and located in the vessel. When liquid is normal the bar graph shall have the colour of the liquid on black background. When it is out of operating range (level high or low) the bar graph shall appear in red when there is an alarm. For interface levels, the bar graph background shall have the colour of the top liquid.

For more than one piece of equipment operating in parallel or on stand-by mode, both pieces of equipment shall be shown on the same mimic. Signals of each will be displayed accordingly.

For Packages, only driven equipment will be shown on the Graphic. Also one common alarm / status, if available, will be used on the detail display. The driven equipment or its tag will be used as a target to access to the driver control or package graphic which contains all alarm indications.

Pumps and Motors shall be displayed as follows:

a. Pump running shall have a “Green” body colour.

b. Normal stop action either from ICSS of Field shall have a “Red” body colour.

c. ESD action on pumps shall have a “Magenta” body colour.

d. Pump selected for stand-by while stopped shall have a “yellow” body colour.

e. Pump tripped due to an electrical fault/” not available” shall have a “Cyan” body colour.

f. Pumps with no feedback in the ICSS shall have the equipment colour.

g. If the pump fails to start or to stop a discrepancy box will appear around the pump and its colour used to indicate the status. When required the tag will be used as a target.

20.14 Fire and Gas Alarm Colour Code

The following colour code shall be used in graphic displays:

Flammable Gas Alarm Level 1: Blue

Flammable Gas Alarm Level 2: Blue

Gas Detector, Toxic Gas Alarm Level 1: Yellow

Gas Detector, Toxic Gas Alarm Level 2: Yellow

Fire Alarms (Smoke Detectors, Flame Detectors, Heat Detectors, Fusible Plugs etc): Red

Manual Alarm Call: Red

Deluge Valve Opened: Red

Security Gate Opened: Red

Refer to AGES-PH-03-002 Appendix B for details of colours.

20.15 Piping Lines

All the process lines source and destinations for main incoming and outgoing lines will be shown with arrows. These arrows will bear the number of the next equipment on the line. For upstream trunk lines, a trunk line number will be shown. This number shall be the target to display the next graphic.

Criss-crossing of process lines or step change for process lines will be avoided.

Generally, process inlet lines will be shown on the left-hand side or at the top of the screen.

Generally, process outlet lines will be shown on the right-hand side or at the bottom of the screen.

When possible, the process lines exiting from a previous display and entering the next display will be at a corresponding location (e.g. bottom of first graphic and top of next graphic...).

21 REMOTE PERFORMANCE MANAGEMENT

If specified, remote performance management requirements shall be planned and incorporated into engineering documentation.

Remote performance management provides information based upon real time data gathered from the multitude of systems and equipment to enable remote analysis allowing informed analysis and fast decisions to be made and executed, thereby improving uptime, maximising efficiency and reducing Operating Expense (OPEX). The real time data comes from the instrumentation sensors, supplier equipment, protection and monitoring systems.

It is essential to set the process of each discipline identifying the base data required for remote monitoring as early as possible in the project schedule so that additional instrumentation and equipment required to support the base data is included at the beginning of the design process.

Engineering disciplines shall have the requisite information and incorporate remote performance management requirements into the engineering documentation as early as possible in the project schedule, preferably in the early define phase before starting to develop the P&IDs, with the final objective to provide the correct instruments to facilitate remote performance management.

22 ESD/SIS REQUIREMENTS

Refer to AGES-SP-04-004 Emergency Shutdown (SIS) System Specification for details on the ESD/SIS system and BMS.

The BMS shall be designed and engineered to the same level of integrity as the ESD system.

Modifications on existing installations shall follow the existing design.

For new installations, the shutdown philosophy for the offshore facilities shall be designed with three shutdown levels:

a. ESD Level 0 Local Shutdowns.

b. ESD Level 1 Production Shutdown.

c. ESD Level 2 General Process Shutdown with automatic depressurization.

For new installations, the shutdown philosophy for the onshore facilities shall be designed with three shutdown levels:

a. ESD Level 1: Total Plant Shutdown with automatic depressurization of the process plant and can only be initiated from central control room.

b. ESD Level 2: Total Plant Shutdown and isolation of process plant.

c. ESD Level 3: Shutdown of individual processes and equipment that would be affected by an isolated or local emergency.

A package unit's ESD requirements are totally integrated in the main plant ESD system.

The following objectives, in order of priority, are to be used as the basis of design:

a. Protection of personnel.

b. Protection of equipment.

c. Protection of the environment.

d. Continuity of production (by minimizing spurious shutdowns).

e. Availability of equipment.

The following descriptions of the levels of emergency shutdown are for general guidance and a project specific shutdown philosophy shall be developed.

For new installations, the ESD system hierarchy shall be divided into three shutdown levels representing increasing degrees of hazard:

a. Equipment or local shutdown

b. System or Sub-System shutdown

c. Hardwired Zone shutdown

Equipment, System and Sub-system shutdowns generally provide protection against equipment or process upset conditions and should normally only be automatically initiated by plant monitoring devices. System or Sub-System shutdowns provide protection against certain critical process or utility upset conditions and might be automatically initiated by process monitoring devices. Hardwired zone shutdown manual push buttons located in the Main Control Room (MCR), the IESs and locally (only applicable in Mechanical Package Units) can also be used to initiate a shutdown.

Redundant field initiating and actuating devices shall be provided based on the requirements from the SIL review.

Where redundant initiating devices are required, three independent instruments shall be provided at the same location, with independent impulse piping and manifolds with isolation. ESD logic shall be arranged for 2oo3 voting to initiate a trip. Operation of a single instrument in the group shall cause an alarm only to be displayed. A discrepancy alarm will be initiated if any one of the three devices are in different status and system logic shall automatically degrade to 1oo2. If only two instruments are used for redundancy, a discrepancy alarm shall be implemented to detect that there is a discrepancy; the 2oo2 logic will act as two out of two when there is no discrepancy alarm and as one out of two if there is a discrepancy alarm.

Inputs to the ESD Control logic shall be either analogue or digital. Analogue outputs shall not be permitted.

Line monitoring is to be provided for ESD/SIS I/O's. For any specific digital inputs where line monitoring may violate the intrinsic safety installation rules, SIL certified "fail safe" interface cards which include line monitoring shall be provided to monitor the circuit from the input card up to the barrier. In such cases IS barriers shall be provided with a line fault detection contact, wired to the ICSS, to monitor the circuit from the barrier to the field device. DO card shall be selected with sufficient power rating to directly drive a field solenoid operated valve (SOV). Line monitoring fault condition action shall be configurable to trip or alarm as part of the ESD/SIS design.

An ESD reset shall not operate a valve. All valves shall be operated locally after an ESD reset to bring them back to their normal operating position. The local command shall not be active if an ESD condition is present. For valves where the reset of the ESD logic resets the valve operation without involvement of field operator, COMPANY approval is required.

Critical control valves requiring a specific start-up position shall have their controller output changed to the required value prior to the interlock being reset. This comparison logic shall be performed in the ICSS and the “Controller Outputs OK” status transmitted to the ESD system as part of the interlock reset logic.

The ESD system design shall aim to maximize reliability and availability of 99.99% with an 8 hours MTTR without introducing a high degree of complexity into hardware or software configuration.

Push buttons shall be guarded type with a flap in the front side to avoid accidental trips. Push buttons and switches shall have integrated illumination feedback indication in same push button / switch as confirmation of action from ESD system.

A first up alarm for each shutdown logic for each unit shall be provided in the ESD system and displayed in the ICS. GPS time synchronizing facility shall be provided for the ICSS and subsystems for time stamping of alarms and events. GPS time synchronisation shall be applied across the whole network so that all alarms and events are time and date stamped at the point of entry into the system, whether that is the ICSS, package or third party system so that alarm and events can be chronologically synchronised.

Only the ESD system shall be capable of by-passing an executive action. A maintenance override shall not inhibit the alarm function. All bypass status alarms shall be available on the ICSS console.

Once a day at a given time (e.g. 08h00. 12h00 etc.), the ICSS shall generate an alarm for each point for which the maintenance by-pass is on, an alarm record showing all active maintenance overrides shall be printed. COMPANY policy shall be observed regarding the length of time that an initiator can be overridden without a temporary Procedure Change Request (PCR), in any event if this time is exceeded an urgent alarm shall be generated at the ICSS Operator console.

Input signals to the ESD System shall be primarily from ‘Smart’ transmitters monitoring pressure, level, flow and temperature. Where switches are used in the field, they should be snap acting type arranged such that shutdown initiation is caused by opening contacts.

Where initiating inputs to the ESD system are from other systems, these shall be configured as normally closed contacts that open to initiate shutdown to achieve fail safe design.

Shutdown initiating signals from other systems shall generally be controlled by output circuits from those systems.

23 FIRE AND GAS SYSTEM

The Fire and Gas System is part of the Integrated Control and Safety System (ICSS) comprising PCS, ESD, F&G, AMS and interfaces to 3rd party systems.

Two dedicated 29” F&G HMI’s configured with all plant related F&G data shall be located in the Fire Station to alert the safety personnel of the location and type of hazard.

Addressable loops shall not be used in the process areas and process buildings however addressable loops are acceptable for non-process buildings that have their own dedicated Fire Alarm panel.

The redundancy shall permit on-line testing of single channels without requiring actual process shutdown. Cards shall be replaceable without plant shut down or loss of F&G detection and protection.

Line monitoring is to be provided for non-addressable F&G I/Os.

Any failure of the system shall be alarmed with details in the F&G system diagnostics and with alarms at the ICSS Maintenance Console and ICSS Operator Console.

Non process building Fire Alarm panels shall display their own system alarms on the panel and send a hardwired common system alarm to the main plant F&G system for display in the Fire Station and via ICSS in the MCR.

The main plant F&G system shall interface with other systems to receive or instruct shutdown initiation requests or to instruct equipment to shut down. Typically, these other systems will include:

a. Non-Process Building Fire alarm panels
b. Building Access panels
c. Public Annunciation (PA) System
d. Security Access Control System (Emergency Exit Doors).
e. CCTV
f. HVAC
g. Very Early Warning Fire Detection Systems (VEWFD)
h. Clean Agent Extinguishing System
i. Deluge and Foam System
j. Package F&G System

24 CYBER SECURITY

Cyber Security (OT Security) requirements are covered in ADNOC specifications AGES-SP-04-001 and AGES-SP-04-004 and a summary of requirements is repeated here as follows:

PCS networks shall form the basis of networking for all elements of facility control and safety systems. The network shall be divided into zones with separate levels of security.

All communication between the ICSS zone and Enterprise zones shall be via a Demilitarized Zone and Firewalls.

Cyber Security implementation for the ICSS including PCS/ESD/SIS systems shall comply to IEC 62443 for safety level SL2 and shall be ISASecure certified for cyber security.

Cyber Security design shall comply with the ADNOC Group Company's Digital Security and Cyber Security policies.

Applied security should have the capability to allow remote performance monitoring by either Company Personnel or, third parties. The VENDOR shall implement UAE national Digital Security Authority requirements after discussing with COMPANY and in compliance with Company Cyber Security policy and procedures.

A cyber security risk assessment as per IEC 62443-3-2-1 shall be performed by COMPANY/CONTRACTOR. VENDOR shall provide all required support for this assessment.

The cyber security risk assessment shall be performed by CONTRACTOR as follows and shall be seen as an iterative and continuous process from hardware freeze to FAT and SAT:

a. Define the risk analysis methodology (for example architecture based).
b. Identify major items (organization, systems, subsystems, networks).
c. Identification, evaluation of the threat scenarios with their impact and likelihood.
d. Reduce the risks by designing adequate countermeasures.
e. Summarize the results in a Risk Register.

The cyber security risk assessment findings and recommendations shall be implemented by VENDOR.

VENDOR shall provide firewalls to enforce data transfer between the different ICSS zones.

The ICSS system software patch update and security programs requirements shall comply to COMPANY Cyber Security guidelines/policies.

All unused ports on switches and routers of the ICSS system shall be disabled to assist in preventing unauthorized access to the ICSS network infrastructure.

VENDOR shall provide Firewall and Malware protection for Cyber Security in line with COMPANY Cyber Security guidelines/policies.

25 SPAREAGE

Spare capacity is covered in AGES-SP-04-001 and AGES-SP-04-004 and is repeated here as follows:

25.1 Installed I/O and Cabinet Space:

Each Marshalling and System cabinet shall be provided with 20% installed and wired spare for each type of I/O card. Each I/O card shall have at least 20% spare I/O channels available. The installed 20% spare shall include all associated terminations, terminal block, cable ducts, trays Field cable spare cores shall be terminated on terminal blocks.

In addition to wired spares there shall be an average 20% empty space inside cabinets for future use.

25.2 Memory/Processing:

Spare memory for application program and database shall be at least 40%. CPU loading shall not exceed 60% of its maximum capacity at full system loading.

25.3 Network and Data Storage

Network loading shall not exceed 60% and data storage utilisation shall not exceed 60%.

25.4 Communication Interfaces:

Communication interfaces shall not be loaded more than 50% at maximum loading after plant start-up.

26 INSTRUMENT NUMBERING AND TAGGING

All instrument numbering and tagging shall be in accordance with relevant project approved numbering system.

SUPPLIER is advised that '**SEQUENCE NUMBERS OF INSTRUMENT TAGGING IS IN THE CONTROL OF COMPANY REGISTRY'**. Dummy numbers may be used by the SUPPLIER during the preliminary stages of the bidding process. CONTRACTOR shall allocate the required block of numbers and the unit number for each Packaged Unit and equipment after Purchase Order award. Packaged SUPPLIER shall utilize the block of numbers assigned to the Packaged Units in his P&IDs and in all other documentation.

All package instruments, equipment, cables, etc. shall be uniquely tagged in accordance with this specification and duplicate items are prohibited. SUPPLIER and CONTRACTOR shall ensure coordination is maintained during all phases of the project to ensure that the numbering requirements are adhered to.

Tag numbers cannot be modified once they have been assigned or approved. If modifications are required to the approved tag number, then the tag number shall be voided, and a new tag number shall be assigned. Tag Numbers voided after creation shall not be re-used.

Document and Drawing numbers and their sequence numbers are also in the control of COMPANY registry. SUPPLIER may use his document and drawing number system, but they shall additionally carry COMPANY's registry assigned numbers after Purchase Order award on all document and drawing submittals.

The electronic filing and numbering system shall be in relational one-to-one correspondence with the hard copy filing arrangement for drawing and document submittals.

27 INSTRUMENT SYMBOLS AND TAGGING

Instrument symbols and Identification shall generally be in accordance with ISA S5.1 to 5.5 for P&ID representation, Tagging, Logic diagrams, Graphic displays etc. and Company Practices. Minor deviations / exceptions shall be identified within the Project specifications, requisitions, documents and drawings.

28 INSTRUMENT PANELS

28.1 Design

Wherever possible, systems shall be designed to avoid the use of field located control panels. Preference is for control panels located in climatically controlled equipment and control rooms.

Field Mounted I/O cabinets in shall be by COMPANY approval.

The type of control panel for each application, operating policy, basis of design and its size and layout, shall be as defined in the project specifications or data sheets.

Field control panels where specified in the data sheets shall be supplied as free-standing assemblies supporting instrumentation and related equipment and protected from the environment during normal operations.

Control panels shall conform to one of the following:

a. CCI P/3.

b. UL 508A.

c. UL 698A.

d. NEMA ICS 6.

e. IEC 60204-1 as specified in the project specifications or data sheets.

Control panel assembly hardware like brackets, nuts, bolts etc shall at least be:

a. Coated steel for indoor control panels.

b. Type 316L Stainless Steel for outdoor control panels or control panels in corrosive service.

Control panels shall meet the service requirements, environment, electromagnetic compatibility, and electrical classification of the area as defined in the project specifications or data sheets.

Control panels shall be designed for installation in true vertical orientation.

If structural vibration is specified in the project specifications or data sheets, control panel shall be provided with anti-vibration mounting.

Control panel design shall incorporate cable entry requirements as follows:

c. For outdoor control panels, cable entries shall be from the bottom or side of the control panel.

d. For indoor control panels, cable entries shall be either bottom entry or top entry.

e. Unused or spare control panel openings shall be plugged or covered.

Bolts, nuts, screws, and fasteners used shall be compatible with control panel material.

Supplier shall operate a system of weight and centre of gravity control and reporting in conformance to the weight control specification if included in the Purchase Order.

Utility consumption requirements for electricity and air (for purged enclosures) shall be provided.

For outdoor control panels, the Supplier shall use IEC 60654-1 or ISA S71.04 to determine if measures such as anti-condensation heaters or breathers or fans are required to prevent internal condensation across all operating conditions specified in the project specifications.

Pneumatic cabinets shall have a vent that prevents overpressure of the cabinet due to failure or leakage of fittings.

Control panels specified for marine applications shall be designed to withstand the vessel movement expected during operations and installation phases.

Door hinges on control panels shall be designed to take the full load of the door, in all positions, including forces generated by vessel movement of control panels installed on marine applications.

Control panels shall be designed to accommodate the loads and stresses experienced during shipping.

Control panels shall be designed for the earthquake (seismic) criteria specified in the project specifications.

28.2 Layout

Individual plant areas shall be located on separate areas or sections of the control panel if specified in the project specifications or data sheets.

Each area shall have a nameplate mounted in the top section of the control panel.

Where control panel covers multiple process equipment:

a. Control panel layout shall follow process flow.

b. Instruments shall be grouped in relation to their application and sequence of operation in the plant.

Control panels containing instruments directly connected to process fluid shall be arranged to ensure that leaks or spills do not damage other equipment in the control panel.

Instruments and associated piping containing process fluids shall only be mounted in freely ventilated cubicles or open control panels.

A rain drip shield shall be permanently installed above all outdoor enclosure door openings to prevent ingress of rainwater.

Heat shield shall be installed over the full length of the control panels if specified in the project specifications or data sheets.

Control panel shall be mounted on standoffs or legs if specified in the project specifications or data sheets.

Control panels specified to be installed in sheltered areas requiring hosing down in the project specifications, shall be mounted on a plinth approximately 130 mm (5 in) high, and be rated to IP 66 in conformance to IEC 60529 or NEMA 4X in conformance to NEMA 250 (as specified in the data sheets).

Controls initiating shutdown action shall be:

a. Located in an easily identified and accessible position.

b. Arranged to minimise the risk of accidental operation.

Semi graphic or annunciator displays shall be placed above indicating, recording, and control instruments, no higher than 2.15 m (7 ft) above the base of the control panel unless subject to approval by Company responsible engineer.

Indicating, recording, and control instruments shall be placed above manual controls.

Except for gauges and annunciation indicators, centreline of top row of instruments on control panel face shall be no higher than 1.7 m (5,5 ft) above the base of the control panel unless subject to approval by Company responsible engineer.

Control panel mounted annunciators shall be clearly visible under all lighting conditions.

Instrument displays shall have anti-reflecting or anti-glare glass.

Instruments shall be mounted for direct access without interference from wire ways, tubing, support brackets, and other instruments so that the calibration, maintenance and removal become easier.

Control panels shall be provided with front or rear or both front and rear access as specified in the project specifications or data sheets.

Control panels shall be provided with swing frames if specified in the project specifications or data sheets.

Temporary protection shall be provided to prevent damage to control panels during installation of the control panel.

Redundant components shall be located on independent backplanes.

28.3 Spares

Control panels shall have 20% spares (unless specified otherwise in project specifications) at completion of factory acceptance testing, for installed and identified future equipment for:

a. Instrument cutouts or empty shelf units.

b. Terminals.

c. Capped bulkhead connections, if applicable.

d. Power distribution circuit breakers.

e. Pneumatic supply takeoffs, if applicable.

f. Each fuse type.

g. Each type of controller I/O point or channel, if applicable.

h. Location for wiring or conduit entry.

I/O points including spares shall be wired to terminal points, if applicable.

Control room control panel spares shall be distributed throughout the control panel.

If control panel design includes provision for spare equipment and future equipment space, space shall be clear of wiring, piping, tubing, and auxiliary equipment.

29 DESIGN FOR MAINTENANCE AND OPERABILITY

29.1 General

Note: Operations and maintenance staff need to be regularly consulted during design of instrumentation and process control systems through Company subject matter expert (SME).

Only with a clear understanding of the operations and the maintenance philosophies can the process control systems be properly selected, designed, and implemented.

Most successful projects have had operators and technicians involved in the installation, configuration and testing of instrument and process automation systems.

Instrumentation shall satisfy the following operational requirements:

Information processing, display, recording and reporting facilities for the presentation of processed measured data in a format suitable for management, operations, technical, commercial, and maintenance personnel. Data links to facility wide management information systems as specified by Company.

The availability of the facility is to be analysed for required reliability and where necessary increase the redundancy of instrumentation to prevent spurious trips.

Means of recording facility variables for fault diagnosis and for the prevention of unscheduled shutdown. Record shall include real time information on sequence of events and facility trips.

Means of processing and recording key information for facility operation and for facility efficiency monitoring.

Measurement, information processing, recording, and automatic sampling for fiscal and accountancy purposes.

Measurement, information processing, recording, and automatic controls for emissions to atmosphere and discharges of liquid effluents to enable adherence to legislative requirements (including environmental and health monitoring systems).

General evacuation alarms with policy for activation and sound levels and frequencies in relation to the surrounding facility.

Regulations applicable to drilling areas on offshore platforms.

Field-proven ability for the application. If an updated version is offered and is advantageous, Contractor shall ensure that a proven fall-back item is available and compatible with the correct software and hardware version.

Note: The main criteria relating to equipment is proof that the equipment is fully operational on a similar sized facility. For example, model numbers of the main elements to be provided on request.

Clearly, there is a compromise between selecting well proven equipment with a very low risk to the project timetable and selecting less well-established equipment with superior facilities for the operating company in the longer term. Specialist advice can be sought in case of doubt.

If the equipment is new technology, obtain references and contact them to ensure the equipment is used in similar application. If not, consider risk mitigation planning.

Supplier support to meet the safety requirements i.e., MTTR time.

Proven support (project management, spares, servicing, and technology) available from supplier near the installation or main Company support base needs to be available.

Information to enable early detection of degradation of facility or equipment due to fouling, wear, or another malfunction. This shall be addressed as part of the overall condition monitoring and maintenance policy for the facility.

Degradation of the facility is not limited to using alarm management and operating envelopes.

30 FACILITY SPARE PARTS

Contractor shall make recommendations for spares holdings for the design.

Spare parts recommendations shall be based on data from suppliers, experience with equipment and parts use in similar applications, and requirements of the operating unit.

Spares required for commissioning shall be part of scope of supply, but operational and maintenance spares will not.

Replacement fuses, I/O cards, IS barriers, etc., are often required to replace faulty items discovered during commissioning.

The following factors and their impact on facility operations shall be considered in making recommendations:

a. MTTR.

b. Spared or single train unit.

c. Critical nature of service.

d. Severity of application, including jobsite environment.

e. Availability of qualified craft maintenance personnel.

f. Accessibility of jobsite to qualified service engineering.

g. Availability of local stock at jobsite.

h. Long delivery / lead items.

i. Deterioration in storage.

j. Economics of ordering high cost items with original equipment such as rough machined forgings, spare rotor assemblies, complete spare units, and subassemblies.

k. Proactive obsolescence management strategies need to be developed, particularly for subsea hardware.

31 OPERABILITY

Instrumentation shall provide information and control of the process, so facility and utilities meet specified requirements for:

a. Safety.

b. Product quality.

c. Throughput.

d. Efficiency.

e. Economic operation.

Local adjustment of control and bypass valves shall have local indication provided.

Indication of variables required for facility and equipment operation during start-up, shutdown, or emergency conditions shall be provided locally.

Requirements for facilities will be identified by Company. It is unlikely that the supplier alone would have the knowledge of the facility or its operation to satisfactorily provide the full facility. Company would develop the concept and engineer as the project proceeds directly or in consultation with the Contractor or specialist consultant.

Additional measurements over and above those necessary for basic facility operation will probably be required (energy observation, advanced control, facility optimisation, oil loss or stock control, or management information schemes). Early specification of such measurement points (even if only in outline) could minimise any risk of project cost escalation and reduce the supplier future scope for extras.

32 INSTRUMENT CONTROL ROOMS AND IES

Plant facilities will be controlled from the Main Control Room (MCR)

32.1 General

The function of the control room is to provide a suitable environment for all operational activities and for fixed equipment installed in it.

Note that Control and Equipment rooms are considered process areas even when they may be part of a building with offices, etc.

The following activities which affect the control room fixed equipment are:

a. overall supervision
b. engineering management
c. data transmission
d. telecommunication
e. fire alarm and security monitoring

The main control room is located outside of hazardous areas. Instrument Equipment Shelters (IES's) are also located in non-hazardous areas.

Control buildings shall preferably be located outside blast overpressure zone and Instrument Equipment Shelters (IESs) may be located inside the blast pressure zone. After finalizing the building location, project specific risk assessment / Quantitative Risk Assessment (QRA) considering all potential risks from existing and new project facilities shall be carried out, to determine the building construction type (blast resistant or conventional) and all other design / HSE requirements.

All control, rack and computer rooms will be pressurized and have entry airlocks. This applies to the Main Control Building as well as IESs.

Control rooms shall be designed based on a third-party ergonomic study and the following standards:

ISA RP60.1	Control Centre Facilities
ISA RP60.3	Human Engineering for Control Centres
EEMUA Publication 201	Control rooms: a guide to their specification, design, commissioning and operation

Cable entry into the Substations, IES, MCR and Analyser shelters shall be routed through Multi cable transit blocks (MCT).

32.2 Lighting

Adjustable intensity LED task lighting shall be used for Operator Workstations. Care will be taken to protect operators from glare.

Other technical rooms shall have LED lighting.

LED lamps shall also be used for Instrument cabinets.

Lighting for control rooms shall be subject to an ergonomics/lighting study.

32.3 False Floors

Control, rack and computer rooms have false floors (minimum 60 cm). False floor shall comply with the requirements specified in the Architectural requirements.

32.4 False Ceilings

Fire-resistant, sound-proof false ceilings working in conjunction with room lighting are to be supplied and installed.

32.5 Noise

Noise will be taken into account and shall meet COMPANY'S requirements for Equipment Noise Control.

32.6 Fire and Gas Detection and Protection

For Fire & Gas System refer to AGES-SP-04-003 Fire and Gas System specification, this specification and Corporate HSE Philosophy.

All plant buildings shall be provided with the necessary fire and gas detection and protection.

Fire and gas detection and protection system will be in accordance with CONTRACTOR'S specification duly approved by COMPANY.

32.7 Telephones, Public Address

Telephone, Intercom and Public address systems communications will be taken into account when specifying buildings and control rooms.

Design of the Public Address system shall include an audibility study of the whole asset.

33 TELECOMMUNICATIONS

Reference Corporate Telecoms requirements for details on the following systems:

a. Telephone Systems.
b. Public Address System.
c. CCTV.
d. Access Control System.
e. Radio Systems.
f. Walky-Talky.

g. Weather Monitoring System.

SECTION C - TESTING AND SUPPORT

34 INSPECTION, TESTING AND CERTIFICATION REQUIREMENTS

34.1 Nomenclature

Instruments and materials for instrumentation have been grouped as shown for the purposes of inspection and testing:

In-line instruments - are instruments which form part of, or are defined as forming part of, the process pressure piping system, such as control valves, positive displacement and turbine meters, venturi and other flow tubes and elements, and displacer type level instruments.

On-line instruments - are those instruments which can be isolated from the process fluids by a valve, such as pressure gauges, pressure switches and transmitters, etc.

Off-line instruments - are all instruments which are not in contact with any process fluid, e.g. receiving-type instruments.

Prefabricated instruments - includes all prefabricated instrument equipment, such as console desks, local panels and system cabinets, etc.

Instrument or instrument systems for equipment packages - are all those instruments or instrument systems necessary to build the package unit as provided by the unit MANUFACTURER.

Construction materials - are materials such as instrument cables, instrument air piping/tubing and instrument impulse lines, etc.

34.2 Classification of Instruments and Instrument Systems

Instruments and instrument systems are considered in the following categories for the purpose of factory inspection:

Category A - For which factory inspection and/or testing are not normally required.

Category B - For which factory inspection and testing shall be carried out.

Category C - For which factory inspection and testing should be carried out.

34.3 General

The testing requirements shall include all aspects such as Functional, Performance and Interface tests.

The Documents & Drawings required for Approval by CONTRACTOR at various stages, shall be as specified in the Mechanical equipment specifications or Purchase Order documents.

SUPPLIER shall have conducted their own tests and recorded the results. The results shall be submitted to CONTRACTOR prior to any inspection by him or inspection waiver or before Dispatch.

A means to record/approve various stages of tests which shall allow testing from card/component/module level to total integration.

As a minimum, the tests shall include the following activities or checks for Instruments or systems, as applicable.

a. Visual & Dimensional check.

b. Bill of material check.

c. Assembly checks.
d. Approved material for installation check.
e. Accessories completeness checks.
f. Mounting detail checks.
g. Ratings check.
h. Leak checks.
i. NDT certificates check, when applicable.
j. NACE certificates check, when applicable.
k. Calibration check.
l. Panels, wiring, trunking, termination, earthing etc. checks.
m. Electrical checks.
n. Enclosure certification checks.
o. EMC certificate check.
p. Functional/ Performance/Operational check.
q. Input/Output (I/O) check including point/channel/module/system cable failure and reinstatement.
r. I/O points check for all types – analogue, contact, pulse, digital/discrete status flags etc.
s. Redundancy checks - Processor, Communication, Memory, Power supply and I/O, as applicable.
t. Time synchronization checks.
u. System Initialization checks.
v. Console checks and/or display checks for control loop configuration.
w. Software loading.
x. Logic checks with authorized issue of Cause and Effect or binary Logic diagrams.
y. Graphics check – Static and Dynamic.
z. Serial mapping check.
aa. Auxiliary systems check –Maintenance PC etc.
bb. Master – Slave controls check.
cc. Supervisory system upload/ download check.
dd. Tagging, Cable numbering, termination ferruling and nameplate check.
ee. Cybersecurity testing and Verification checks.

Package equipment control systems shall be tested along with the package equipment instruments. When package equipment controls are implemented on the plant ICSS and/or ESD, then CONTRACTOR shall engineer and arrange to provide the relevant ICSS / ESD systems.

Instrument cables shall be inspected and tested in accordance with AGES-SP-04-006 Section 15.1.

The testing facilities and procedures shall comply with the specified Quality Control procedures and shall be subject to CONTRACTOR approval.

In case of witnessed tests, the MANUFACTURER shall provide a detailed procedure and test formats at least a month prior to the testing schedule for COMPANY review and acceptance.

The tests shall be witnessed by the COMPANY or their nominee. Where the tests are not witnessed, the MANUFACTURER shall provide copies of the test reports for COMPANY approval before shipment.

34.4 Factory Inspection and Testing

34.4.1 General

This section defines the responsibilities of the SUPPLIER in performing the inspection and testing of the system. Testing is to involve all components and subcomponents of the system. For prefabricated, skid mounted packages, all instruments and controls shall be installed and fully tested to the CONTRACTORS satisfaction prior to delivery.

The SUPPLIER is responsible to perform the complete functionality and performance testing of the Packaged Equipment control system, along with the communication interfaces.

CONTRACTOR reserves the right to inspect and witness testing of all instrumentation and electrical wiring prior to shipment from the SUPPLIER'S factory. Before CONTRACTOR'S inspection, the SUPPLIER'S engineers shall have carefully inspected, checked, and tested all instrumentation to verify full compliance with the drawings and specifications listed in the Purchase Order.

Particular attention shall be given to:

a. Accessibility.
b. Impulse line Hook-ups as per project approved drawings.
c. Straight length requirements for orifice plate and control valve installations.
d. Supporting arrangements.
e. General aspects such as the colour scheme for control panels, etc.
f. Color-coding, if applicable.
g. Quality of wiring/cabling.
h. In-line instruments.
i. Earthing connections.
j. Painting.
k. Documentation.
l. Labelling and tagging.

All instruments supplied by the SUPPLIER shall have calibration certificates signed by the QA/QC engineer of the SUPPLIER or his SUB-SUPPLIER'S. These documents shall be available during inspection. All Instruments shall be calibrated by the SUPPLIER just prior to any test at factory or at site and copies shall be provided by SUPPLIER.

Calibration certificates shall be submitted to the CONTRACTOR for approval and record. This certificate shall be incorporated in the final manufacturing report.

The SUPPLIER shall provide valid calibration certificates for primary test equipment used, approved by the local authorities or a recognized testing laboratory.

Test requirements shall include an operational test of all instrumentation and control devices. Functional testing of each device is acceptable where the Equipment operation is not practical. However, this is subject to COMPANY approval. Of special concern is the testing of the alarm and safety shutdown system.

The above tests shall be done utilizing supplier's standard SHOP Control System. To test and prove that control monitoring and protection functions are correctly interpreted and implemented by CONTRACTOR, the supplier should send his representatives to witness a simulated functional test during factory acceptance test of the respective control systems or during FAT (Factory Acceptances Test).

The SUPPLIER shall provide the required skilled and qualified manpower together with all necessary test equipment from his own resources to perform the shop testing. If necessary, the SUPPLIER shall arrange the assistance of specialist SUB-SUPPLIER'S to implement the test procedures. These tests shall be at least equal to those, which shall be applied during the site instrument pre-commissioning procedures.

The SUPPLIER shall provide a factory test procedure for approval by the CONTRACTOR / COMPANY for use during the package instrument acceptance testing.

34.4.2 Phases of Tests

Testing will be carried out and witnessed by the CONTRACTOR and COMPANY representatives at various stages as the Packaged Equipment systems equipment is manufactured and assembled, at locations detailed below:

a. Pre-Factory Acceptance - conducted at the manufacturing facility of the Equipment system SUPPLIER.

b. Communications interface testing - conducted at the premises of Equipment system SUPPLIER.

c. Factory Acceptance Test, including Performance test - conducted at the manufacturing facility of the ICSS system SUPPLIER.

d. Integrated Factory Acceptance Test - conducted at the staging facility nominated by the SUPPLIER and approved by COMPANY.

e. Site Integrated Test (SIT) - conducted at the job site.

f. Site Acceptance Test (SAT) - conducted at the job site.

All formal testing will be conducted in accordance with a COMPANY and CONTRACTOR approved written test procedure. The test procedures will be furnished by the SUPPLIER to the contractor at least 3 months prior to the Factory Acceptance Test for approval. COMPANY and CONTRACTOR representative will witness the entire FAT. The SUPPLIER, CONTRACTOR and COMPANY representative at the successful conclusion of testing will sign off the FAT documents.

34.5 Shop Inspection

COMPANY or their nominated third-party inspector shall have full access to inspect the MANUFACTURER's works during the manufacturing and/or before shipment as per the approved Inspection & Testing Plan.

Inspections shall be made to confirm that the MANUFACTURER and final product is in accordance with the specified standards and specific project requirements.

CONTRACTOR representative will periodically visit the Equipment SUPPLIER'S shop facilities and inspect system progress from a hardware and software perspective.

34.6 Pre-Factory Acceptance Test

The standard supplier procedures for thermal cycling of parts or the system shall be provided in the SUPPLIER'S proposal.

The system equipment will be inspected by CONTRACTOR representative prior to Pre- Factory Acceptance Test for satisfactory quality and workmanship.

The entire Pre-Factory Acceptance Test (Pre-FAT) procedure must have been successfully exercised on the system by the SUPPLIER prior to the FAT.

34.7 Communications Interface Testing (CIT)

Communications interface testing shall be conducted at the respective Packaged Equipment system SUPPLIER'S premises using ICSS equipment (PC based emulator) fully representative in terms of hardware and software interfaces of the equipment to be installed at site. ICSS SUPPLIER shall produce test procedures and result documentation for these tests in a standard format wherever possible, copies of which will be issued to the other SUPPLIER'S.

SUPPLIER shall develop a program to schedule all such tests and allocate adequate resources to implement the testing without impacting the remainder of the system.

34.8 Factory Acceptance Test (FAT)

Factory testing and Staging shall be done at a single location and all testing/-staging facilities and equipment to test shall be in the scope of SUPPLIER. Prior to this Factory Acceptance Test (FAT), SUPPLIER shall submit for approval written FAT procedures.

Minimum of 21 days prior notice shall be given to COMPANY for witnessing FAT.

The FAT will include the testing and acceptance of both hardware and software systems.

The SUPPLIER shall be required to submit FAT procedures for approval prior to starting any tests. A copy of the COMPANY approved FAT procedures and related printouts shall be furnished to COMPANY representative.

The FAT procedure shall contain a block diagram of every test hook-up. The procedures shall include a matrix of all tests, which shall be maintained during testing, detailing the dates of each test and whether it passed or failed. At the start of testing a listing shall be completed by the SUPPLIER, and agreed by CONTRACTOR / COMPANY, detailing all software and firmware revisions and equipment serial numbers. This shall be maintained during testing with all changes clearly indicated by both date and time. The testing shall be structured in a logical manner and shall cover, but not be limited to, the following:

a. Earthing isolation and continuity measurements at sample locations
b. Power up, power distribution verification plus Voltage and Current measurements
c. ICSS Diagnostics
d. Input / Output and reporting / annunciation tests
e. Screen content and functionality
f. Hardware/software tests for all loops except for ESD, FGS and PCS loops which will be tested during IFAT
g. System response tests with all I/O simulated at worst network loading conditions

h. Power supply test (single feeder failure, momentary power loss, individual Equipment power supply loss, etc.)

i. RFI and EMI testing

j. FAT for systems should include all accessories, peripherals, etc. for the system

All system programs must be complete and resident in the digital system prior to the start of FAT. All listings must be free of pencilled (patched) corrections. The system must be free of patches.

All hardware diagnostic programs will be run at the start of FAT. These must be the diagnostic programs, which have been used for processing the system in the SUPPLIER'S factory. ICSS SUPPLIER shall be responsible for generating the FAT procedures that shall include "pass/fail" criteria.

Diagnostic programs which are tested during FAT will be shipped to the staging area with the system. During FAT the system shall be made available to COMPANY for sufficient periods to verify satisfactory performance.

All process inputs and outputs must be simulated during the FAT. The purpose of this simulation is to provide a facsimile of the production process, with all points of an individual loop or interconnected loops hooked up for test simultaneously.

34.9 Integrated Factory Acceptance Test (IFAT)

All subsystems interfacing with the ICSS will be tested additionally during ICSS IFAT (integrated Factory Acceptance Test). Prior to this, the subsystem shall be factory tested at the respective subsystem SUPPLIER's factory for its proper operation.

At the FAT, the integrated system shall be tested 100% for the communication interface functioning, communication (network and serial link) load, the ICSS data base configuration and displays associated with the subsystem. Subsystem I/O and configuration will be tested at the respective vendor's factory and software simulated for the integrated test. ESD and FGS Cause & Effect matrix configuration, jog test, first-out alarm with ESD time tag shall be fully tested along with corresponding display animation.

Maintenance console functions including sub-system diagnostic alarms shall be tested.

Witnessing of these tests by SUPPLIER is mandatory. The SUPPLIER shall participate and confirm in writing the adequacy of ICSS design in terms of safe start-up, operation, maintenance, shutdown and diagnostics for Equipment and package Equipment and its instruments.

34.10 Site Installation Test (SIT)

The Site Integrated Test (SIT) shall include the test of all the interfaces between systems. All system SUPPLIERS shall provide all required assistance and all required test and calibration equipment for their system.

The Site Integrated Test (SIT) shall be divided in four activities as outlined below.

34.10.1 Individual System Functional test

For each system this test shall repeat all the FAT tests related to system behaviour:

a. system power-up

b. power failure

c. redundancy

d. hardware diagnostics

e. test of all other system basic functions

The test shall demonstrate that the system has been received in good condition, is installed correctly, is healthy and can successfully be used for further site activities.

34.10.2 Pre-commissioning Procedure (PCP)

The Pre-commissioning procedure (PCP) shall include the test of logics, loops. During the PCP, all the interfaces between systems shall be working in good condition. All system SUPPLIER's shall provide all required assistance and all required test and calibration equipment for their system.

34.10.3 Logic Function Check

Logic function check shall start only after the Individual system functional test described above has been completed.

For each system all internal logic functions shall be tested by simulation from the field instruments (test shall be done against Cause and effect charts and logic diagrams). This test aims to verify that the logic functions operate according to specification to allow the loop test to proceed loop by loop. ESD jog test from the ICSS, dynamic power flow logic, C&E display animation shall be done as part of logic test.

34.10.4 Test of System Integration

Test of system integration shall start only after the Individual system functional test described above has been completed.

For each Instrument Equipment Shelters (IES), when all systems are interconnected, the test of system integration shall be done to verify that links between different systems operate according to specification and that all redundant links automatically switch over if the link in service fails. The test shall verify that all data transfers between ICSS and sub-systems operate correctly and within specified time limits and shall include all system diagnostics and their display.

This test shall also demonstrate that the first-out data with time stamp and time synchronization function between the ICSS and the other systems, including alarming and sequence of event reporting, works according to specification.

34.10.5 Loop Tests

Loop test shall start only after a successful Test of system integration and after completion of the Logic function check, both as described above.

For each loop (hardware or software) the loop test shall be done with all systems connected and operating. The loop test shall allow the test from the end device to the ICSS display with all other system processing the signal involved. For analogue signals check shall be done at three points (0%, 50%, 100%) and for any alarm point. When a logic function is tied to a loop, the test shall check that logic initiation is correct and that any inhibit function is operating correctly.

34.11 Site Acceptance Test (SAT)

Prior to Site Acceptance Testing (SAT), SUPPLIER shall submit for approval written SAT procedures and a means to record /approve various stage of tests which shall allow testing to verify all tests done at FAT stage and in addition include tests to verify changes thereafter, including punch-list items' verification. All special test equipment and test equipment requested by COMPANY shall be provided by SUPPLIER at this stage also and identified for use in SAT procedure.

The site acceptance test shall start after the acceptance by COMPANY of the systems to be tested. For a period of thirty days, the systems behaviour and performances during routine working shall be monitored. Check of network load shall be done in the course of the Site Acceptance test. After thirty days if the system operates as per specification, Site Acceptance of the system shall be approved.

34.12 Certificates of Acceptance

At the satisfactory conclusion of the FAT, a factory Certificate of Acceptance shall be provided by the Packaged SUPPLIER for signature by the CONTRACTOR and COMPANY.

At the satisfactory conclusion of the SAT (Site Acceptance Test) a final Certificate of Acceptance shall be prepared by the Equipment SUPPLIER. Attached shall be all test records, receipt for documentation and spare parts plus any other pertinent records regarding the vendor’s delivery. The document becomes a Certificate of Final Site Acceptance which CONTRACTOR and COMPANY shall review and approve.

34.13 Services by the SUPPLIER

Field inspection and testing of instrument systems shall be the responsibility of the CONTRACTOR and Equipment SUPPLIER.

The Equipment SUPPLIER shall supply supervision, specialist personnel and all necessary materials to support the inspection and shop/site testing as defined above, including all the equipment and signal generation adequate to simulate all inputs simultaneously on a loop containing multiple input.

This section defines the responsibilities of the VENDOR in performing the inspection and testing of the system. Testing is to involve all components and subcomponents of the system. The VENDOR is responsible to perform a complete functionality test of all the communication interfaces. 100% testing of all I/O points and functions are required.

The VENDOR shall be responsible for inspection and quality assurance of the materials and standard of workmanship furnished. Testing will be carried out and witnessed by the CONTRACTOR and COMPANY representatives at various stages as the systems equipment is manufactured and assembled, at locations detailed below:

a. Pre-Factory Acceptance – conducted at the manufacturing facility of the VENDOR.

b. Communications Interface Testing – conducted at the manufacturing facility of the VENDOR.

c. Factory Acceptance Test – conducted at the manufacturing facility of the VENDOR.

d. Integrated Factory Acceptance Test – conducted at the Integrated System VENDOR’S staging facility agreed by the COMPANY.

e. Site Integrated Test (SIT) – conducted at the job site, to be determined by the VENDOR and approved by the COMPANY.

f. Site Acceptance Test (SAT) – conducted at the job site.

All formal testing will be conducted in accordance with a detailed written and COMPANY approved test procedure. The test procedures will be furnished by the VENDOR to the CONTRACTOR at least 2 months prior to the Factory Acceptance Test for approval. COMPANY and CONTRACTOR representative(s) will witness the entire FAT. Each formal acceptance test must be signed by VENDOR, CONTRACTOR & COMPANY representative at the successful completion of the test(s).

34.14 Shop Inspection

CONTRACTOR representative will periodically visit the VENDOR'S shop facilities and inspect system progress from a hardware and software perspective.

34.15 Certificates of Acceptance

At satisfactory conclusion of the FAT, a factory Certificate of Acceptance shall be provided by the VENDOR for signature by the CONTRACTOR. At the satisfactory conclusion of the SAT (Site Acceptance Test) a final Certificate of Acceptance shall be prepared by the VENDOR. Attached shall be all test records, receipt for documentation and spare parts plus any other pertinent records regarding the vendor's delivery. The document becomes a certificate of Final Site Acceptance which COMPANY shall review and approve.

34.16 Pre-Factory Acceptance Test (pre-FAT)

The standard vendor procedures for thermal cycling of parts or the system shall be provided in the VENDOR'S proposal. The system equipment will be inspected by COMPANY/CONTRACTOR representative prior to Pre-Factory Acceptance Test for satisfactory quality and workmanship. The entire Pre-Factory Acceptance Test (Pre-FAT) procedure must have been successfully exercised on the system by the VENDOR prior to the FAT.

34.17 Communications Interface Testing (CIT)

Communications interface testing shall be conducted at the respective VENDORS premises using ICSS equipment (emulator) fully representative in terms of hardware and software interfaces of the equipment to be installed at site. VENDOR shall produce test procedures and result documentation for these tests in a standard format wherever possible, copies of which will be issued to the other Vendors. VENDOR shall develop a programme to schedule all such tests and allocate adequate resources to implement the testing without impacting the remainder of the system.

34.18 Factory Acceptance Test (FAT)

The FAT will include the testing and acceptance of both hardware and software systems with 100% testing. All system programs must be complete and resident in the digital system prior to the start of FAT. All listings must be free of corrections (patches). The system must be free of patches. All hardware diagnostic programs will be run at the start of the FAT. These must be the diagnostic programs, which have been used for processing the system in the VENDOR'S factory. VENDOR shall be responsible for generating the FAT procedures that shall include "pass/fail" criteria. Diagnostic programs which are tested during FAT will be shipped to the staging area with the system. During FAT the system shall be made available to COMPANY for sufficient periods to verify satisfactory performance.

All process and serial link inputs and outputs must be simulated during FAT. The purpose of this simulation is to provide a facsimile of the production process, with all points of an individual loop or interconnected loops hooked up for test simultaneously.

A copy of the signed off FAT procedures and related printouts shall be furnished to COMPANY representative. The VENDOR shall be required to submit FAT procedures for approval prior to the test. The FAT procedure shall contain a block diagram of every test hook-up. The procedures shall include a matrix of all tests which shall be maintained during testing, detailing the dates of each test and whether it passed or failed. At the start of testing a listing shall be completed by the VENDOR, and agreed by CONTRACTOR/COMPANY, detailing all software and firmware revisions and equipment serial numbers. This shall be maintained during testing with all changes clearly indicated by both date and time. The testing shall be structured in a logical manner and shall cover, but not be limited to, the following:

Earthing isolation and continuity measurements at sample locations

a. Power up, power distribution verification plus Voltage and Current measurements
b. System/ application software
c. System Diagnostics
d. System communication, redundancy, back-up testing
e. Input / Output and reporting / annunciation tests
f. Screen content and functionality
g. Hardware / software tests for all loops except for ESD, and F&G loops, which will be tested during IFAT.
h. System response tests with all I/O simulated at worst network loading conditions
i. Power supply test (single feeder failure, momentary power loss, individual unit power supply loss, etc.)
j. RFI and EMI testing
k. FAT for systems should include all accessories, peripherals, etc. for the system.

34.19 Integrated Factory Acceptance Test (IFAT)

All subsystems interfacing the integrated control system will be tested during IFAT at Integrated System Suppliers/ Vendor’s facility. Prior to this the subsystem shall be factory tested at the respective subsystem vendor’s factory for its proper operation.

At the IFAT, the integrated system shall be tested for the communication interface functioning with all the subsystems, communication (network and serial link) load, the data base configuration and displays associated with the subsystem shall be tested (100%). Subsystem I/O and configuration will be tested at the respective vendor’s factory and software simulated for the integrated test. ESD and F&G Cause & Effect matrix configuration, jog test, first-out alarm with ESD time tag shall be fully tested along with corresponding display animation.

Maintenance console functions including sub-system diagnostic alarms shall be tested. Witnessing of these tests by package unit supplier is required. The package unit supplier shall confirm the adequacy of ICSS design in terms of safe start-up, operation, maintenance, shutdown and diagnostics for package unit and its instruments.

34.20 Site Integrated Test

The Site Integrated Test (SIT) shall include the test of all the interfaces between systems. All system VENDOR’S shall provide all required assistance and all required test and calibration equipment for their system.

34.20.1 Individual System Functional Test

For each system the individual system functional test shall repeat all the FAT tests related to system behaviour:

a. System Power-up
b. Power Failure
c. Redundancy
d. Hardware Diagnostics
e. Test of all other system basic functions

The test shall demonstrate that the system has been received in good condition, is installed correctly, is healthy and can successfully be used for further site activities.

35 SPARE PARTS

35.1 Spares

35.1.1 General

Instrument spares shall be readily usable by replacing the faulty item within the packaged equipment. If special jumpers or address switches made to be changed, those shall be made ready for the specific application and shall be listed clearly on the spare part, packing documents with reference to the project number and machine contract number.

SUPPLIER shall provide order preparation services for spare parts and consumables during the warranty period and for 2 years operation. This cost assumes that the procurement service will be executed within a period such that the order to the SUPPLIER is placed before the corresponding SAT is carried out. COMPANY will place the order directly to the SUPPLIER. All cost of material, packing, shipping, clearing, custom duties. If applicable, delivery to site will be paid directly by COMPANY.

35.1.2 Start-Up and Commissioning Spares

The SUPPLIER shall supply start-up and commissioning spares, as required in order to avoid using any of the recommended spares. The cost of start-up spares shall be quoted separately in advance for review. The time scales and procedure for repair and/or replacement of parts shall be stated in the SUPPLIER'S bid.

35.1.3 Operational Spares

The SUPPLIER shall review the equipment (including tools, testing and calibration equipment) offered in his proposal and shall include a comprehensive recommended spare parts list enough for two (2) year's continuous operation of the equipment and one-year consumable spares.

35.2 Special Tools

SUPPLIER shall furnish, all special tools required for installation, commissioning, dis-assembly and re-assembly of his equipment. These shall include but not limited to the following per equipment package:

a. Software (including any third-party software) configuration devices for all controllers, I/O modules. Software (including any third-party software) for reconfiguration of operator interface.

b. Diagnostic software and hardware for all electronics.

c. CONTRACTOR as well as technician level diagnostic software for all machine condition/performance monitoring, machine condition/performance evaluation.

d. Any special instrument tools to dismantle impeded instrument items.

e. Special test clamps or leads for electronic/instrument checks, if any.

SUPPLIER shall provide with his proposal a list of special tools included in his offer. For multi-unit installation of three and more than three identical units, two sets of special tools shall be provided. For two identical units, one set of special tools shall be provided. Tools required for use during normal operation shall be suitable for the specified area classification. All special tools shall be packaged in metallic containers.

The SUPPLIER shall supply all standard and special tools, test and calibration equipment necessary for site installation, pre commissioning and SAT.

The SUPPLIER shall provide his standard items of special tools and test equipment.

36 PAINTING, PRESERVATION AND SHIPMENT

Packing, protection, preservation, identification, marking, and storage shall be in accordance with AGES-SP-07-004 Painting and Coating and COMPANY Standards.

Paint system must be capable of withstanding environmental conditions at site for a period of 7-8 years on the European scale of rusting.

36.1 Surface Protective Coating and Painting

Instruments and the following items shall be protected against paint used on equipment and process units:

a. Glass fronts
b. Moving parts, i.e., control valve stems and positioners
c. Vents and drains
d. Name/data plates
e. Tube fittings and cable glands
f. Isolation and vent valves

Panels and equipment in Control Rooms and Instrument Equipment Shelters (IES) shall be painted so that the dominant type of equipment will determine the colour scheme for the rest of the equipment.

External Painting and coating shall comply with COMPANY Specification AGES-SP-07-004 Painting and Coating Specification.

Painting shall be to MANUFACTURER's standard for items not addressed in COMPANY specification or undefined within this specification, in such case SUPPLIER shall furnish his standard painting procedure for approval prior to manufacturing for approval. Colour and finish shall be to MANUFACTURER's standard for items not identified by COMPANY.

Instrument cases shall be preferably corrosion resistant Stainless steel. Non-stainless steel metallic cases shall have marine painting. Marine coating finish is required on both materials.

Colour Finish Schedule (to BS 4800 or approved equal by COMPANY).

36.2 Packing and Shipping

Preparation for shipment shall be in accordance with the Preservation and Export Packing Corporate requirements. SUPPLIER shall be solely responsible for the adequacy of the preparation for shipment provisions with respect to materials and application, and to provide equipment at the destination in ex-works condition when handled by commercial carriers.

All material shall be packed/covered with suitable material to provide physical protection during transit, ordinary storage and handling operations. Packing shall ensure that material will be protected from water/humidity/dust. Adequate protection shall be provided to prevent mechanical damage and atmospheric corrosion in transit and at the jobsite.

Preparation for shipment and packing will be subject to inspection and rejection by COMPANY'S / CONTRACTOR'S inspectors. All costs occasioned by such rejection shall be to the account of the SUPPLIER. Special precautions required during transport & handling shall be clearly marked externally on packings of all materials.

Packing shall be road-worthy, sea-worthy (open deck storage) and air-worthy as per transportation basis.

After inspection and test, equipment shall be completely free of water and dry before start of preparation for shipment.

Equipment shall be packed, securely anchored, and skid mounted when required. Bracing, supports, and rigging connections shall be provided to prevent damage during transit, lifting, or unloading. All temporary bracing/supports shall be marked “REMOVE BEFORE EQUIPMENT COMMISSIONING AND STARTUP".

Cabinets and instrumentation shall be packed separately; other loose or small parts shall be properly packed and protected to prevent loss or damage to equipment. The cabinet shall be braced or strengthened to avoid distortion. The Vendor shall be liable to make good any damage during transit.

Flanged openings shall be protected with metal cover plates to prevent damage and ingress of foreign matter during shipment. Covers shall be a minimum of 6 mm thick and shall be installed with a full-size gasket using a minimum of 4 full diameter bolts. Large diameter flanges will require enough full diameter bolts to seat the cover all around. The cover and flange shall be taped for waterproof protection.

Open ends of tubes and pipe shall be capped for protection and to prevent ingress of foreign matter. Female threaded connections shall be plugged with solid metal pipe plugs, and male threaded connections shall be protected with full metal pipe caps.

Separate, loose, and spare parts shall be completely boxed. Pieces of equipment and spare parts shall be identified by item number and service and marked with CONTRACTOR 's order number, tag number, and weight, both inside and outside of each individual package or container. A bill of material shall be enclosed in each package or container of parts.

Exposed finished and machined surfaces, including bolting, shall be given a coating of rust inhibiting compound. Internal metal surfaces shall be sprayed or coated with a suitable rust preventative prior to shipment. Openings shall be suitably tagged to indicate the rust preventative applied.

Heavy-duty plastic foil and silica gel shall be used for safeguarding and sealing of all parts sensitive to moisture. Provide additional external reinforcing against mechanical damage. Mechanical seal assemblies shall be fully protected from rusting and entry of moisture and dirt.

Each consignment shall be clearly marked with the complete Purchase Order, requisition number, description of its contents and its intended project name.

One complete set of the installation, operation, and maintenance instructions shall be packed in the boxes or crates with equipment. This is in addition to the number called for in the Purchase Order.

Construction site and CONTRACTOR shall be notified in advance of the delivery date and time of transport.

The SUPPLIER shall be fully responsible for supplying all necessary documentation to ensure smooth and rapid transportation/customs clearance of the equipment.

36.3 Preservation and Storage

Preservation/Storage methods shall follow MANUFACTURER’s recommendations. Instructions shall be provided listing special requirements for long-term storage. All equipment and material shall be preserved, and export packed in accordance with Project Preservation and Export Packing Corporate Standards.

Equipment and materials shall be protected to withstand ocean transit and extended period of storage at the jobsite for a minimum period of 18 months. Control panels, racks, cabinets and equipment containing electronics shall be stored in a warehouse whose environment is artificially controlled to prevent dew point condensation.

Equipment shall be protected to safeguard against all adverse environments, such as: humidity, moisture, rain, dust, dirt, sand, mud, salt air, salt spray, and sea water.

SUPPLIER shall provide clear instructions for the type of storage required at site after receipt of the material.

37 COMMISSIONING

The pre-commissioning and commissioning shall form part of site support services and the spares & consumables used during this stage by SUPPLIER shall be replenished free-of-cost to CONTRACTOR, at the successful conclusion of commissioning services.

Electrical and instrumentation loop checks shall follow IEC 62382.

38 TRAINING

38.1 General

Training for COMPANY personnel shall be planned just before plant start-up by competent trainers from SUPPLIER's Head Quarters. Training by commissioning engineers is not acceptable. Training shall be specific to the supplied equipment system and cover all aspects of the operation and maintenance.

The trainers shall have total familiarity with both the equipment hardware and software and shall be able to answer queries raised during the training sessions.

The proposed Trainers' curriculum vitae and course material shall be submitted for COMPANY approval 8 weeks before the start of the training sessions. SUPPLIER shall arrange the required training equipment (demo kits, simulator, etc.). CONTRACTOR shall specify different type of training sessions for each system such as familiarization courses, pre-engineering training, Operator training and Technician training, etc.

38.2 Training Philosophy

SUPPLIER shall provide customized training approved by COMPANY both on site and at the SUPPLIER facility for COMPANY personnel.

38.3 Training Course Documentation

For each trainee who will attend a training course, a copy of the complete training course, notes, and drawings shall be provided to COMPANY eight weeks prior to the commencement of the training course. The copies shall be retained by the trainees on completion of the training course and shall be the property of COMPANY.

In addition, five (5) copies of the customized training course documentation shall be available on site prior to the installation and pre commissioning for reference purposes.

38.4 Operator Training Course

A syllabus shall be prepared and provided, and a location recommended. Operator manuals shall be made available to COMPANY prior to this course.

38.5 Maintenance Training Course

The purpose of the course is to train technicians for first line fault diagnosis, and repair by replacement.

38.6 System Configuration Course

The purpose of this course is to enable COMPANY Engineers to be able to modify system configuration control and sequencing and to modify a build new graphics.

a. Basic System Introduction

b. Peripherals

c. Operator Consoles

The SUPPLIER shall recommend the location for this training.

38.7 Training Aids

The SUPPLIER shall list training aids required for above courses.

38.8 Operator Training Simulator

The Operator Training Simulator shall form an integrated part of the Operator Training and Testing of the systems and procedures and documentation shall reflect this.

39 DOCUMENTATION / MANUFACTURER DATA RECORDS

39.1 Documentation

The CONTRACTOR shall define the requirements for the MANUFACTURER / SUPPLIER drawings and documentation for CONTRACTOR'S and COMPANY's approval or information as listed in the associated Manufacture's Record Book.

The Packaged Unit SUPPLIER shall provide all documents needed to allow engineering and design of the package, the installation, start-up and maintenance of all instrumentation. All references to any instruments on any SUPPLIER document or drawing shall be by Tag Number.

Comments made by CONTRACTOR on drawing submittal shall not relieve the Packaged Unit SUPPLIER or SUB SUPPLIER of any responsibility in meeting the requirements of the specifications. Such comments shall not be construed as permission to deviate from requirements of the Purchase Order unless specific and mutual agreement is reached and confirmed in writing by COMPANY.

All drawings and documents shall be submitted in COMPANY approved software and electronic formats for the project as well as hard copies. CONTRACTOR shall ensure SUPPLIER utilizes the same drawing format, contents style, presentation, electronic format, as per the Project procedures.

The Packaged Unit SUPPLIER shall provide a legend within the documents or drawings detailing all the symbology employed.

Each drawing shall be provided with a project standard drawing title block in the bottom right-hand corner incorporating the following information:

a. Official trade name of the Packaged Unit SUPPLIER.

b. The Packaged Unit SUPPLIER'S drawing number.

c. Drawing title giving the description of contents whereby the drawing can be identified.

d. A symbol or letter indicating the latest issue or revision.

e. Purchase Order number and item tag numbers.

Revisions to drawings shall be identified with symbols adjacent to the alterations, a brief description in tabular form of each revision shall be given, and if applicable, the authority and date of the revision shall be listed. The term "Latest Revision" shall not be used.

Documents and drawings shall be provided only in the following sizes, as shown in Table 39.1:

Table 39.1 – Drawing Sizes

Drawing Size	Dimensions
A4	210 mm X 297 mm
A3	297 mm X 420 mm
A2	420 mm X 594 mm
A1	594 mm X 841 mm
A0	841 mm X 1189 mm

No handwritten documents or drawings shall be accepted.

All SUPPLIERS' documents and drawings shall strictly follow revision marking (vertical line in right border) along with (strikethrough) for deletion and (underlined) for addition & modifications in hard copy as well as in electronic copy. All documents/drawings shall be submitted showing the last revision and changes/additions made along with a list of item-by-item SUPPLIER response to COMPANY comments. When COMPANY approves a document with "No Comments", SUPPLIERS shall issue such documents/drawings as "COMPANY approved issue". In this issue, the document shall be same as previous submission except that it will only show revised/added version without any revision marks.

CONTRACTOR shall thoroughly review SUPPLIER'S documents to ensure compliance to Project documents / drawings and shall submit only the marked-up copy of SUPPLIER documents.

All instrument and electrical schematics shall be drawn with the power off and any switches in the absence of process parameter (level, temp. pressure…etc.).

Instrument Loop diagrams for local control and monitoring shall be generated by the Packaged Unit SUPPLIER as defined on the CONTRACTOR forms. For integrated controls supplied by the CONTRACTOR, the Packaged Unit SUPPLIER shall provide drawings indicating interface to package instrumentation and equipment boundary junction boxes to enable the CONTRACTOR / ICSS SUPPLIER to complete all other loop diagrams.

The Packaged Unit SUPPLIER shall provide functional logic diagrams in ISA 5.2 symbology for special and/or proprietary systems in his supply. Detailed write-ups for start-up, sequence control and safeguarding and (emergency) shutdown procedures shall be prepared by Packaged Unit SUPPLIER for the entire package. The CONTRACTOR shall prepare functional logic (Cause and Effect Charts) diagrams for the integrated controls based on information provided by the Packaged Unit SUPPLIER.

If applicable, the Packaged Unit SUPPLIER shall provide trip relay listing with detailed information for maintenance (Tag Numbers, Terminals, Set Point, Range, Location, etc.).

39.2 Manufacturers Record Book

39.2.1 Deliverables

The listed documentation shall be considered to be the minimum requirements. Additional requirements shall be discussed and agreed with COMPANY where specifically required by individual projects. All drawings and documents shall be written in the ENGLISH Language.

39.2.2 Specific Requirements

The Manufacturing Record Book (MRB) for each packaged equipment item shall be compiled in accordance with the following requirements and the applicable codes:

a. Documents shall be written in English.

b. Documents shall be in a legible, reproducible form.

c. The number of MRB's to be supplied shall be specified in the request for quotation (RFQ) and the Purchase Order (PO) documents.

d. Drawings and other data shall be based on the A4 series sizes, and all drawings larger than A4 size shall be folded to A4 size so that title box and status decal are visible from the front and inserted into pre-punched plastic sleeves.

e. The contents of the MRB shall be collated into a logical sequence in accordance with the Purchase Order/Contract requirements and in accordance with Shop Inspection and Certification Corporate Requirements. Tabbed dividers shall be provided to separate the sections of data.

f. MANUFACTURER/ SUPPLIER shall submit a detailed MRB index/contents list for CONTRACTOR approval within 8 weeks of order placement unless stated otherwise in the Purchase Order.

g. The reports shall be provided in loose leaf form with numbered pages in 2.5 inch hard cover A4 size binders (MANUFACTURER / SUPPLIER can use narrower binders if appropriate subject to COMPANY/ CONTRACTOR approval). Binder mechanism shall be four pillar interlock type. The colour and finish of the binder will be advised by CONTRACTOR / COMPANY during a pre-production meeting.

h. Multiple binders must be clearly referenced i.e. "1 of xx", and each contains an index detailing how many volumes and the contents of each volume.

39.3 Installation, Operation and Maintenance Manual

SUPPLIER shall refer to AGES-SP-04-006 for the Installation, Operation and Maintenance Manual requirements.

39.4 SUPPLIERS Responsibilities

As manufacturing of the packaged equipment progresses, the MANUFACTURER / SUPPLIER shall compile the MRB with all the design, manufacturing, inspection, tests, and certification information on a per tag item number basis. Documents that are common to more than one item shall be duplicated in each report.

The MANUFACTURER / SUPPLIER shall present the MRB's to the nominated inspector at each inspection visit. It is also their responsibility to ensure that Inspection & Test Plans are signed and dated by the nominated inspector on the day of any Inspection / Test. The spine and cover of each binder shall indicate the following as a minimum:

a. Manufacturing Data Report

b. Project Name

c. MANUFACTURER / SUPPLIER Name

d. Purchase Order No.

e. Equipment No.

f. Equipment Description

g. MANUFACTURER / SUPPLIER Order Ref. No.

h. MANUFACTURER / SUPPLIER Doc. No.

i. Date of Issue and Revision.

Alterations, deletions, or additions to certification are not normally permitted, and a new document must be prepared. However, where this is not possible the alteration must be approved, signed and dated. Additions and revisions shall be added to the documentation, not as a replacement but as an addition to the existing records.

The Manufacturing Data Report shall, after being accepted by clear endorsement of each page by stamp, date and signature of the nominated inspector, be submitted to the CONTRACTOR.

Manufacturing Data Report documents that are already approved by CONTRACTOR with a signed and dated endorsement do not require additional endorsement by the nominated inspector at the MANUFACTURER / SUPPLIER works. The nominated inspector shall endorse the index as correct with reference to documents embodied within the MRB. For multi-page documents the first page (used for approval) shall clearly state the document total number of pages and each page shall be numbered. CONTRACTOR can use dated stamps, subject to COMPANY approval (without requirement for signature endorsement) providing stamp is uniquely identifiable to individual inspectors.

The original and the required number of copies shall be forwarded promptly after the completion of the equipment in accordance with the terms and conditions of the purchase order. If the order is subject to inspection by COMPANY / CONTRACTOR, the release note for the acceptance of the equipment shall only be issued when the manufacturing report, including the required number of copies, is presented.

The use of coloured markers to highlight certificates shall not be permitted.

The use of correction fluids is not permitted.

When test / material certification is called for, these certificates are to be countersigned by COMPANY / CONTRACTOR.

39.5 MANUFACTURER / SUPPLIER QC Document and Certification

SUPPLIER document and deliverables shall be as per the schedule of deliverables identified in the associated appendix, which shall be updated with required document submission times according to the project schedule requirements.

40 GUARANTEES AND WARRANTY

The SUPPLIER shall guarantee, in accordance with the general conditions, that the provided equipment shall meet the performance conditions specified in this specification, the purchase order, associated documents and Data Sheets.

The SUPPLIER will provide warranty services for a minimum period of 18 months from purchase date or 12 months after has been installed, whichever is later. The warranty services shall comprise any diagnostic services, on-site repairs or replacements, and technical support required to ensure that the control valves operate as specified during the defined warranty period and shall be provided at no additional cost to COMPANY.

SECTION D - DOCUMENTATION

41 STANDARD DRAWINGS

41.1 Instrument Index

The instrument index will be a complete listing of all tagged instruments and shall include as a minimum, the following:

a. Tag number
b. Process description
c. Vendor and model number
d. P.O. and requisition no.
e. Layout drawing no.
f. P&ID
g. Loop drawing
h. Hook-up detail (impulse line, electrical hook-up, weatherization, pneumatic, air supply and mounting details)
i. Remarks
j. Calibration range and alarm, trip settings.
k. Data sheet no.
l. Line no. And specifications
m. Junction box number

A typical Instrument Index format shall be included in all EPC tenders to ensure homogeneity within the whole site complex.

Instrument index shall include all packages, SUB-VENDORS equipment's as well as process tags.

41.2 Construction and Layout Drawings

Construction drawings will contain instrument locations for all tagged instruments that have signals to or from devices.

41.3 Plant Standard Details

Plant standard details will show installation details for electrical, pneumatics, process hook ups and mounting arrangement.

Each detail will contain a specific reference number and a material take-off listing for electrical, pneumatic, process, and mounting materials. The Instrument Index shall be used to generate tag listings for the details.

41.4 Loop Drawings

Loop drawings shall be produced for:

All hardwired signals connected to systems (ICSS / ESD Fire and Gas, Machinery Monitoring, etc.), including package units instruments.

Where instruments are wired to one system but transmitted to a second system via a serial link, the loop diagram shall depict an indication of this.

Where loops involve multiple systems, transmission of signals or information between systems shall be clearly shown.

Each loop shall contain as a minimum the following information:

a. Loop number
b. a standard presentation of the loop
c. Instrument location
d. Calibration/alarm data
e. I/O card locations (i.e., rack, file, slot)
f. wiring terminations (with terminal numbers) between field instrumentation, I/O cards, panel instruments and junction boxes, if applicable
g. instrument cable numbers
h. J. B. location and number
i. Final element fail safe status.
j. Reference Drawings, number/continuation
k. instrument tag number
l. service description

Notes:

Loop drawings shall follow ISA standard with Company additional comments on the same.

Complex loops (control/sequence/ESD) (e.g. boiler control loops) should be supported by narrative description. These loops shall be presented in the same sheet to the extent possible; otherwise consecutive sheets shall be used with a cross-reference.

41.5 Logic Diagram Drawings

Logic diagram drawings shall include binary operation function sequences, interlocks, interaction and interrupts using ISA standard symbology. Diagrams will flow from left to right where possible. The diagram should be supported by a narrative description of the function. This is mandatory for complex logics.

41.6 ICSS, PLC, and Computer Block Diagrams

These overviews will show how the system hardware is tied together with hi-ways, serial links and major instrument cables. There shall be a plant level simplified overview and detailed overviews which show smaller section of plant with actual amount of hardware estimated. This shall be based on the system in the market that require maximum space, power, heat load to result in conservative sizing of Satellite Instrument Shelters (SIS) and Control Rooms.

Also earthing for each of these systems will be shown in a separate drawing.

In addition to the fields populated during the FEED phase of the project, the following additional fields shall be populated as a minimum by EPC CONTRACTORS during detailed design phase:

a. Signal type (Voltage free, pulse, 120 V AC, 24 V DC)
b. Valve Control action (direct / reverse)
c. Parallel area (to avoid parallel equipment being allocated to same I / O card)
d. Foundation Fieldbus segment number
e. Valve Criticality for allocation to Foundation Fieldbus segments
f. Long / Short format Service Description
g. Alarm and Trip Set points
h. Alarm Priorities
i. Instrument Engineering Units and Range
j. Signals that shall be Redundant (e.g. ICSS AO)
k. Signals that shall be segregated i.e. Independent protective
l. Instrument Manufacturer
m. Instrument Model no.
n. Transducer range (for calibration of transmitters by vendor; generally required for D / P transmitters
o. Mechanical Relay no.
p. Independent Logic Device (ILD) / Independent Safety Device (ISD) drawing no.
q. Instrument Location drawing no.
r. Instrument mounting detail drawing no.
s. Instrument Hook-up drawing no.

SECTION E - APPENDICES

APPENDIX A1. TUBING, FITTINGS AND VALVE MATERIAL SELECTION

A1.1. General

The Instrument tubing, fittings and valve requirements are identified in the following sections, along with the Tubing, Fittings and Valves selection table. All Instrument tubing, fittings and valves materials shall fully comply with the associated project environmental and service conditions.

All Instrument tubing shall be metric and be suitable for compression fittings.

All tubing within this Specification may also be used for certain process applications such as analyser sample systems and chemical injection connections provided that the tubing and fittings are confirmed by COMPANY as meeting the requirements for that application.

Threaded connections shall be avoided by use of manifolds and valves with integral compression or flanged connections if possible. Flanged connections with integral compression connections should be used.

Materials utilised in the manufacture of the specified items shall conform to the requirements of the current editions of the specifications, codes and standards.

All tubing, fittings and valve materials shall be new and in current production. SUPPLIER shall check and confirm the delivery and production schedule for the materials being selected.

Tubing pressure and temperature ratings shall satisfy the pressure and temperature design requirements identified within ASME B31.3, or equivalent that shall be subject to COMPANY approval.

To prevent incorrectly rated tube or fittings being installed, all items of a similar material and size shall be rated for the most onerous specified duty.

SUPPLIER shall maintain a system to ensure that different materials, sizes and fittings are segregated and easily identified e.g. permanent marking.

A1.2. Instrument Tubing

Instrument process and pneumatic tubing shall be metric and will generally be 12mm OD as a minimum. Alternative tube sizes of 6mm OD, 15mm OD, 20mm OD, 25mm OD and 40mm OD are also acceptable.

All instrument tubing surfaces shall be clean and free from scratches, die marks and other visible blemishes.

For seal gas systems, lube oil systems, and other auxiliary systems, tubing is allowed only inside panels and instrument connections. Tubing in 316L stainless steel or higher grade of corrosion resistance alloy metallurgy (as required by process conditions) shall be used.

To ensure compatibility between instrument tube and fittings, all tubing supplied shall conform to tube manufacturer's recommendations for the following manufacturing variables (within the requirements of this Specification):

a. Material.

b. Method of manufacture.

c. Wall thickness and outside diameter.

d. Surface finish.

e. Hardness.

f. Concentricity.

g. Ovality.

All instrument tubing and fittings used on sour service shall be certified to metallurgical requirements of ISO 15156 (NACE MR 0175) or ISO 17945 (NACE MR 0103).

Manufacturing procedures shall be submitted for COMPANY review for the selected tubing.

The following tubing materials that can be selected are identified below:

A1.2.1 Stainless Steel (316SS, UNS S31600. UNS S31603)

316 Stainless steel tubing shall have a minimum Molybdenum content of 2.5%, be cold drawn, seamless to ASTM A269 / A632 dual certified TP316 and TP316L (or equivalent). Stainless steel tubing shall comply with the mechanical properties identified in ASTM A269 / A632.

Tube shall be bright annealed with a maximum hardness of HRB 90.

Tolerances shall meet or exceed ASTM A269 / A632 (or equivalent) and OD tolerances shall not exceed ± 0.1016 mm.

316 Stainless Steel is not permitted for use within marine / coastal area environments, due to suffering from pitting and crevice corrosion.

A1.2.2 Super Duplex Stainless Steel (UNS S32750)

Super duplex stainless steel (SDSS) combines a high mechanical strength, along with extremely high corrosion resistance in marine environments. SDSS can also be used within higher pressure applications.

Super duplex stainless steel tubing shall be cold drawn, seamless to ASTM A789 / A789M UNS designation S32750 (or equivalent).

Instrument SDSS tube shall be bright annealed with maximum hardness of HRB 32.

Pitting Resistance Equivalent (PREN) shall be greater than 40 in order to provide a high resistance to pitting corrosion. In addition, SDSS offers high resistance to crevice corrosion and stress corrosion cracking.

Tolerances shall meet or exceed ASTM A789/ A789M (or equivalent) and OD tolerances shall not exceed ± 0.127 mm.

A1.2.3 6% Molybdenum (UNS S31254)

6% molybdenum (6Mo) tubing shall be cold drawn seamless to ASTM A269 UNS S31254 (or equivalent).

All instrument 6Mo tubing shall be fully solution annealed with a maximum hardness to match the requirements of the fittings.

Typical maximum hardness values range between HRB 90 and 96.

Tubing tolerances shall meet or exceed ASTM A269 (or equivalent) and OD tolerances shall not exceed ± 0.127 mm.

Pitting Resistance Equivalent (PREN) shall be greater than 42 in order to provide a high resistance to pitting corrosion. In addition, 6% molybdenum tubing offers high resistance to crevice corrosion.

A1.2.4 Alloy UNS C69100 (Tungum)

Tungum is a proprietary, high tensile brass with proven service experience offshore and excellent external resistance to marine atmospheres. 316L fittings have been successfully used with Tungum and are considered the industry standard.

Tungum is susceptible to liquid metal embrittlement (LME) if mercury, acetylene or ammonia is present and Tungum shall not be used on sour service or non-process applications.

Tungum (Alloy UNS C69100) tubing shall be cold drawn, seamless and pickled to ASTM B706 Temper TF00 (precipitation hardened) UNS designation C69100 (or equivalent).

Tube shall have a maximum hardness of HRB 80.

Tolerances shall meet or exceed ASTM B706 (or equivalent) and OD tolerances shall not exceed ± 0.1016 mm.

A1.2.5 Titanium Grade 2 (UNS R50400)

Titanium grade 2 tubing shall be cold drawn seamless to ASTM B338 UNS designation R50400 (or equivalent).

Tube shall be fully annealed with maximum hardness of HRB 85.

Titanium tubing is light in weight because of its lower density, which makes the titanium tube more desirable where weight could be an area of concern.

Tolerances shall meet or exceed ASTM B338 (or equivalent) and OD tolerances shall not exceed ± 0.1016 mm.

A1.2.6 Alloy 625 (UNS N06625)

Alloy 625 (UNS N06625) is an austenitic nickel-iron-chromium alloy with additions of molybdenum, copper and titanium. Alloy 625 is resistant to chloride stress corrosion cracking, and combined with molybdenum and copper, provides substantially improved corrosion resistance in reducing environments when compared to conventional austenitic stainless steels. The chromium and molybdenum content of Alloy 625 provides resistance to chloride pitting, as well as resistance to a variety of oxidizing atmospheres.

Alloy 625 is also commonly known as Inconel 625.

Alloy 625 tubing shall be cold drawn seamless to ASTM B163 or B444 UNS N06625 (or equivalent).

Tube shall be fully annealed Class 1 with maximum hardness of HRB 90.

Tolerances shall meet or exceed ASTM B829 (or equivalent) and O.D. tolerances shall not exceed ± 10%.

A1.3. Instrument Tube Fittings and Clamps

A1.3.1 Tube Fittings

Tube fittings shall be:

a. Mechanical grip.

b. Gaugeable to prove correct installation.

For services where twin ferrule tube fittings are not suitable, applications shall use flared, cone and thread or hydraulically applied fittings.

Fittings shall be designed for metric tube sizes.

Screwed female fittings shall not be used except as part of valve or manifold bodies if the working pressure rating is achieved. Screwed female fittings have less available wall thickness which results in a lower working pressure rating.

Fittings shall conform to the relevant material requirements.

Fittings or ferrules from different manufacturers shall not be mixed and fittings shall be used with correct wall thickness tubing in conformance to manufacturer's recommendations.

SUPPLIER shall ensure, by reference to tube manufacturer's guide that the materials supplied are correct for the application specified.

Nuts shall be coated with Supplier's recommended material to protect the threads against galling.

A1.3.2 Threaded Connections

NPT shall be used for all threaded fitting connections.

Threads shall be in conformance to ASME B1.20.1 but with reduced tolerances to ensure nominal or better thread engagement.

a. For male threads the tolerance shall be between zero turns large and one turn small using a standard test ring gauge.

b. For female threads the tolerance shall be between one turn large and zero turns small using a standard test plug gauge.

System design temperature may require a reduction in the maximum allowable pressure rating of any screwed connection. Refer to the data sheets for the maximum pressure rating.

Threads shall not be seal welded.

A1.3.3 Tube Clamps

Tube clamps used on stainless steel materials shall be of a type to prevent chloride induced corrosion problems previously experienced with enclosed type clamps.

Clamps shall enable quick assembly to perforated trays without damage to tube surfaces

Tube clamps shall:

a. Be made of non-corrosive material, Stainless Steel Type 316 or flame-retardant plastic.

b. Not cause mechanical damage to the tubing in case of vibration.

c. Not allow water to accumulate between tubing and tubing clamp when installed, to avoid crevice corrosion.

A1.4. Instrument Valves

Instrument tubing valves shall be needle, or ball type valves.

Valves shall have bodies and wetted parts as specified in Section A1.5, and suitable for the service requirements of the process fluid.

A1.5. Tubing, Fittings and Valves Selection

SUPPLIER shall select the Tubing, Fittings and Valves materials of construction to be installed in Table A1.1 and the corresponding notes.

Table A1. 1 – Tubing, Fittings and Valves Material Selection

Type Code	Tubing	Fitting	Valves	Temperature limits (See Note 1)	Service Duty	Sour Service
A1	316SS	316SS	316SS	≤60°C (140°F)	Instrument Pneumatic service. See Notes 2, 3, 10.	NO
A2	6 Mo	6 Mo	316SS	≤60°C (140°F)	Instrument Pneumatic service. See Note 2, 10. 11.	NO
A3	Tungum	316SS	316SS	≤200°C (392°F)	Instrument Pneumatic service. See Notes 2, 5, 11, 12, 14, 15.	NO
H1	SDSS	SDSS	SDSS	≤70°C (158°F)	Instrument Hydraulic service.	NO
H2	6 Mo	6 Mo	316SS	≤60°C (248°F)	Instrument Hydraulic service. See Notes 2, 3, 10. 11.	NO
H3	316SS	316SS	316SS	≤60°C (140°F)	Instrument Hydraulic service. See Notes 2, 3, 4, 10. 14.	NO
P1	6 Mo	6 Mo	6 Mo	≤120°C (248°F)	Instrument Process Service. See Notes 6, 10. 11, 14.	YES
P2	Tungum	316SS	316SS	≤200°C (392°F)	Instrument Process Service. See Notes 2, 3, 12, 14.	NO
P3	Alloy 625	Alloy 625	Alloy 625	≤260°C (500°F)	Instrument Process Service. See Notes 6, 7, 10. 11, 14.	YES
P4	SDSS	SDSS	SDSS	≤70°C (158°F)	Instrument Process Service. See Notes 6, 10. 11, 14.	YES
P5	6 Mo	6 Mo	316SS	≤60°C (140°F)	Instrument Process Service. See Notes 2, 3, 6, 10. 11 14.	NO
P6	316SS	316SS	316SS	≤60°C (140°F)	Instrument Process service. See Notes 2, 3, 10. 14.	YES
T1	Titanium	Titanium	Titanium	≤130°C (266°F)	Instrument Process service. See Note 8.	NO

Notes:

i. Higher temperatures are possible with derating of the maximum design pressure.

ii. 316L Stainless Steel can also be used for all tubing, fittings and valves referenced 316 Stainless Steel within Table 1.

iii. 316 Stainless Steel shall be used for tubing and associated components for non-marine / non-coastal sites or at existing onshore site where its use has been successful.

iv. For subsea equipment hydraulic supply duties at marine locations, 316 Stainless Steel may be used within an enclosure and isolated from exposure to the external marine environment.

v. For non-process duties at marine locations, the preferred material is Tungum. Tungum shall not be used if there is a risk of hydraulic fluids becoming contaminated with H_2S, mercury, acetylene or ammonia.

vi. 6Mo, Alloy 625 and SDSS shall be used for marine locations, if production fluids are expected inside the tubing.

vii. Alloy 625 (Inconel) may be considered for extreme environments for which other materials may be considered marginal.

viii. Titanium and titanium-based alloys may be considered for extreme environments, although galvanic coupling to carbon steel and other ferritic alloys shall be avoided.

ix. Chemical injection tubing and fittings material selection for chemical injection duties shall consider:

   1. Corrosivity of chemical in its intended concentration and purity.

   2. Effects of increased temperatures and contamination of injection chemicals caused by proximity to and/or backflow of produced fluids.

x. 316SS, 6Mo, 625 and SDSS shall be used for non-marine / non-coastal locations.

xi. Tungum, 6Mo, 625 and SDSS shall be used for marine locations.

xii. 316 Stainless Steel fittings shall be used with Tungum tubing.

xiii. Material selection for valve bodies shall conform to that for associated tubing class defined in Table 1.

xiv. 6Mo, 625 and SDSS materials used in sour service applications shall conform to the requirements of industry standard ISO 15156 (NACE MR 0175) or ISO 17945 (NACE MR 0103). SUPPLIER shall ensure materials comply with the requirements defined within this Specification.

xv. Tungum shall not be used in sour service.

APPENDIX A2. TYPICAL EARTHING DIAGRAM

Figure 1 Typical Earthing Diagram